

Economic Analysis of Alternate Methods of Allocating NO_x Emission Allowances

Prepared for the Acid Rain Division
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I. Background, Objectives, and Results

The three related ozone transport rulemakings – the SIP call, the section 126 rulemaking, and the FIP – all envision reducing NO_x in the East using a cap-and-trade approach. In this type of approach, a limited number of NO_x emission allowances is made available to the regulated community; one allowance must be surrendered by a source for each ton of NO_x emitted in the ozone season. By buying or selling allowances, sources can control the degree to which they must control their emissions. A source that finds emission controls to be particularly expensive can buy allowances, in essence, arranging to have another source take over some of its control burden.

Regulatory programs of this kind must have a procedure for the initial allocation of the allowances. Though the allocation question was left to the States in the SIP call, EPA must decide on the allocation system in the FIP and the section 126 rulemaking. EPA proposed three options for the initial allocation to electricity generators, in which distributions of allowances would be updated periodically in response to the fuel used or the electricity produced by individual sources.

Before deciding on one allocation system, EPA requested that ICF Consulting study the consequences of adopting the three options that EPA had proposed relative to each other and to an array of other systems. ICF Consulting conducted the study requested by EPA, and has produced this report on its findings. The options to be compared, and the criteria used for the comparisons, were provided to ICF Consulting by EPA. The results of ICF Consulting's analyses, as reported in this document, indicate the likely differences from one EPA option to another along the dimensions (e.g., cost, emissions, prices) selected by EPA for analysis. The report does not, however, reach conclusions as to which option EPA should select or prefer.

In preparation for the analysis, EPA first constructed a set of six “core” options, consisting of combinations of characteristics relating to the timing of any changes in the allocations, the basis of any changes, and the recipients of the allocations. Key distinctions involved whether the use of a generating unit in a given year would change that unit's allocation in the future; whether the allocation would depend on the unit's inputs or its outputs; and whether non-fossil units would receive any allocations. The options were defined in some detail and the detailed options to be analyzed were indicated to ICF Consulting. The relative consequences of the options for the electricity market were then projected using both basic market analysis and detailed computer simulations. For the simulations, the same Integrated Planning Model (IPM) used by EPA for the SIP call and section 126 analyses was set up to recognize different allowance allocations. IPM was selected by EPA for the assessments to ensure that the analysis conducted by ICF Consulting would be consistent and compatible with the economic analysis of the SIP call and section 126 analyses, and because IPM has the flexibility to simulate the effects of allocation changes and can generate output measures relating to almost all of the issues of interest to EPA.

In evaluating the options, EPA wanted to consider each one's consequences in terms of environmental quality, program cost, and the distribution of costs. As presented below, the analysis conducted by ICF Consulting in response to EPA's direction predicted that updating allocation systems would result in somewhat higher program costs, generally lower nationwide emissions, and more generation within the capped region, while keeping electricity prices from rising as much as with permanent ("once-and-for-all") allocation mechanisms. The lower electricity prices (again, relative to a cap-and-trade program with a permanent allocation) would tend to shift the costs of the program from electricity users onto the electricity producers. The analysis also found that updating on the basis of fuel input rather than electricity output would result in higher costs, higher fuel use, and higher emissions of CO₂. Finally, separate but related analyses found that allocation mechanisms would have very little effect on the production of power from non-fossil and renewable sources.

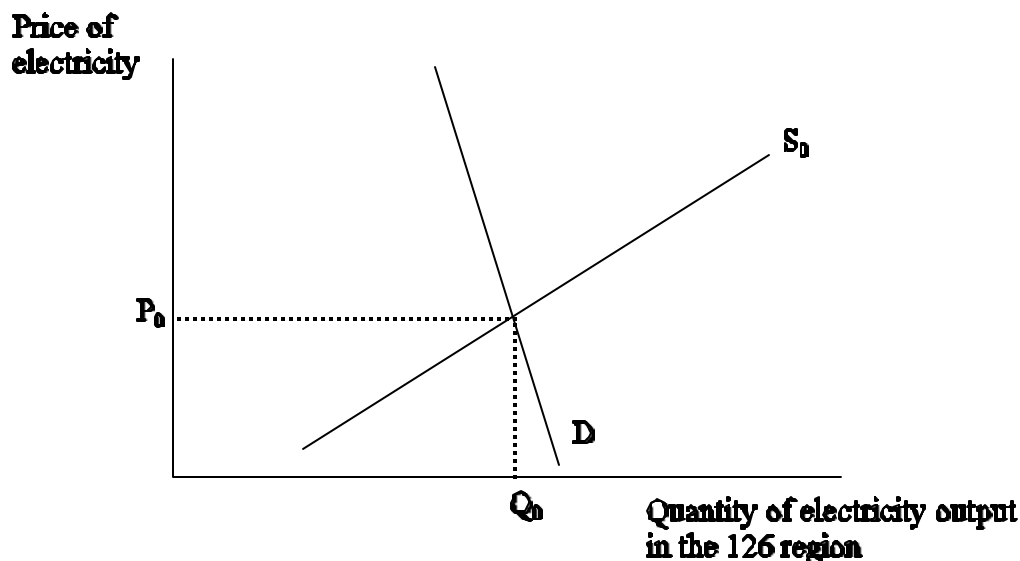
The following sections define a baseline or reference case; introduce the economic analysis as conducted by ICF Consulting; lay out the EPA options that were analyzed; discuss several economic issues; examine the effect of allowances on non-fossil units; and present the results of IPM simulations of the options.

II. The Reference Case

Six alternate rules for allocating NO_x emission allowances to the electric utility sector are discussed in this report. To compare the effects of these rules, a reference case is established in which a cap-and-trade allowance system is used to cut ozone-season NO_x emissions in a region of 19 states and the District of Columbia (the "20 jurisdictions"). This region was selected in response to the NO_x cap-and-trade program proposed by EPA on October 21, 1998 as the section 126 remedy. EPA's proposal included sources in 20 jurisdictions in the control program on the basis of both the one-hour ozone National Ambient Air Quality Standard (NAAQS) and the 8-hour NAAQS that was made final by the Agency on July 16, 1997.

In response to a U.S. Court of Appeals decision regarding the revised 8-hour NAAQS, EPA proposed on June 24, 1999 to indefinitely stay the 8-hour portion of the rule pending further developments in the ongoing NAAQS litigation. This stay resulted in a proposal to include 13 jurisdictions in the section 126 control remedy rather than the original 20. Because the analysis contained in this report began shortly after the October 21, 1998 proposal, and significant portions of the analysis were complete prior to the June 24, 1999 proposal, it considers a NO_x cap-and-trade

Figure 1: The market for electricity before new NO_x rules



program for the entire 20 jurisdiction area rather than revised 13 jurisdiction region. ICF Consulting expects that the general conclusions of the analysis should apply well to other regional breakdowns, including the 13-jurisdiction section 126 region. This expectation is based on the fact that the underlying theory behind the analysis of the effects of the options, which was fully supported by the simulation analyses, is not sensitive to the size of the affected region.

For this reference case, we assume that the allowances must be purchased initially from the federal government, through an auction or similar mechanism. The effects of such a system on the market for electricity is illustrated in Figures 1 and 2, which also serve to introduce the basic economic framework used in this report. In Figure 1, D represents the demand for this electricity. The demand curve slopes downward – that is, consumers want to purchase less electricity from suppliers in the 20 jurisdictions when they charge higher prices. This downward slope has two causes. First, at higher prices, consumers economize on their use of electricity. Second, and perhaps of more importance, consumers will prefer to substitute electricity that is generated outside of the 20 jurisdictions if that electricity becomes more economical. S_0 represents the supply of electricity generated in the 20 jurisdictions prior to the imposition of the new NO_x rules that require additional controls. S_0 is shown with an upward slope because, to supply more electricity at any given time, more and more expensive generators have to be added to the generation mix. Suppliers will not be willing to do this unless the price rises to cover the higher per-unit costs of the added generation. The price of electricity in the 20 jurisdictions can be expected (according to basic economic theory) to settle at the point where S_0

intersects D: at that price (P_0), both generators and consumers are content with the same quantity (Q_0).¹ (This analysis assumes that the electricity market is freely competitive, which is likely to be close to accurate by the time the NO_x rules were proposed to go into effect.)

When a NO_x reduction program is introduced through a cap-and-trade system, the supply curve (which is based on the marginal costs of producing electricity) shifts upward in two increments. This shift is shown in Figure 2. The first increment is in response to the new variable emission control costs borne by the industry, and is shown in the figure as the marginal cost of new emission controls. As a concrete example, this shift may come from the added cost of the urea used by an SNCR unit. If the urea for producing another MWhr of electricity costs \$0.70, for example, then the operator of a unit equipped with SNCR will not want to offer the same amount of electricity unless the price goes up by \$0.70 per MWhr. (The total new variable control costs are shown in Figure 2, as well.)

The reason for the second incremental shift in supply is more subtle, and relates directly to the rules of the cap-and-trade system. Under these systems, a producer generating another MWhr of electricity must, in addition to buying some incremental fuel and other materials (such as urea), surrender enough allowances to cover the unit's residual NO_x emissions. As a concrete example, suppose the SNCR-equipped unit introduced above emits NO_x at the rate of 0.15 lbs/mmBtu even with the SNCR unit running. If its operator considers increasing output by one MWh, and if the unit requires 10 mmBtu to produce each MWh, then the operator must count on surrendering 0.15 lb/mmBtu times 10 mmBtu/MW or 1.5 pounds' worth of allowances. Allowances are valuable; if they must be bought from the government or in the market, 1.5 pounds might cost \$2.50. Thus, this operator would not be willing to supply the same amount of power unless the price rose by an extra \$0.70 (to cover the extra per-MWh cost of running the SNCR system) *and* an extra \$2.50 to cover the extra per-MWh cost of buying the allowances. This need for an extra \$2.50 per MWh to be willing to supply the same quantity is the reason that the supply curve shifts upward by the second increment shown in Figure 2.

In total, these additional costs cause the electricity supply curve to shift upward from S_0 to S_1 , resulting in an increase in electricity price from P_0 to P_1 and a reduction in electricity produced in the 20

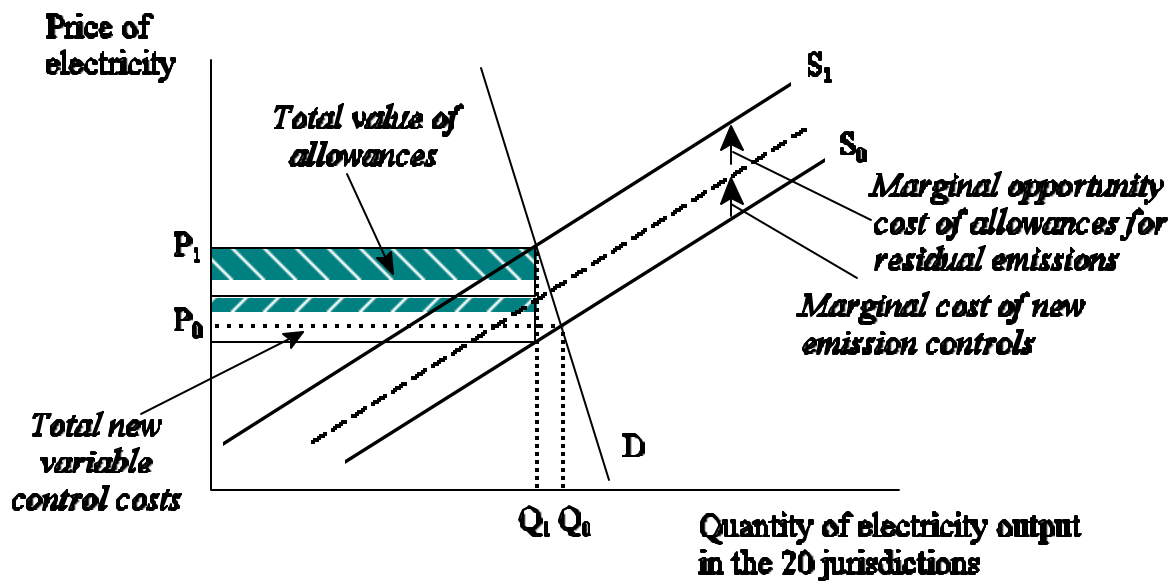
¹The supply and demand situation shown in the exhibit is a simplification that is relevant from the point of view of the industry as a whole, and for seasonal demand for electricity in aggregate. The upward sloping supply curve is made up of small contributions from a large number of units, each with a slightly different incremental operating cost -- at higher prices and greater demand, more and more high-cost units are dispatched. The price in the exhibit represents the average market value of electricity, which actually varies throughout the day. The market can look different from the point of view of the operator of a single unit, which might have relatively constant incremental operating costs, while facing a demand function that offers a different price for each time of day. Despite the complexity added by the change in the value of electricity by time of day, the basic electricity market dynamics are captured well by the simple picture shown in Figure 1.

jurisdictions from Q_0 to Q_1 . The higher price also fosters an increase net electricity imports from outside the 20 jurisdictions, where electricity is relatively less expensive because the new NO_x rule is not applicable.² For the purpose of comparing the allocation rules, the post-cap supply curve, S_1 , and the associated equilibrium price and quantity, are used as the reference case.

III. Allocation rules

There are three key elements to be considered when describing a freely distributed allowance allocation rule: the timing of the allocations, the data relied on for determining the allocation, and the recipients of the allocation.³ Each of the three elements has two alternatives from which to choose, implying eight possible combinations. However, because two such combinations are difficult to implement, the remaining six options provide the “core” from which to choose. Each of these options and their key elements are defined below. Supply and demand curves are then used to show

Figure 2: The market for electricity after new NO_x rules



²In a competitive market, producers outside the capped region, who do not need to give up allowances when they produce more electricity and emit more NO_x , will be able to compete more successfully with producers inside the capped region. At any given price, uncapped producers will offer relatively more electricity than capped producers; in response, the market equilibrium will shift toward less production in the capped region.

³An *auction* is another system for allocating allowances. It differs from the systems that were proposed by EPA and analyzed in this report in that it requires even the initial recipients of the allowances to pay for them explicitly.

differential impacts of EPA's core alternatives on the electricity market.

A. The timing of the allocation

The two principal systems being considered for allocating allowances are differentiated by the possibility of a change in the allowance allocation in the future. A *permanent* system calls for a fixed allocation that is never changed.⁴ An *updating* system is not fixed, but instead changes over time according to some rule that depends on the actions of the participants after the implementation of the program.⁵ A permanent system, therefore, establishes a fixed distribution of the benefits associated with the free distribution of allowances, whereas an updating system allows those benefits to be redistributed with each new update.

The choice between a permanent or updating system is crucial because it determines the incentives for the firms receiving allowances. As explained in the next section, a permanent system will generally have little, if any, impact on the behavior of the firms once the system is put into place. An updating system, however, can be expected to influence the decisions made by operators of affected units. Because updating systems call for changes in the allowance allocation at periodic intervals in the future, firms have an incentive to do more of the activity that will earn them freely distributed allowances. Thus, the ability to earn future allowances causes firms to alter their behavior compared to when they do not have such an opportunity.

B. The data relied on for determining the allocation

The two principal data metrics or "yardsticks" being considered as a basis for making a freely distributed allowance allocation are a firm's *fuel input* and its *electricity output*. Economic theory suggests that allocating allowances in proportion to output should encourage greater fuel efficiency than allocating in proportion to fuel input, which would give a direct incentive to use more fuel. This prediction was tested as part of the analysis of options. In addition, the basis of the allocation would have a direct impact on the distribution of economic benefits (in that owners of existing units that are less fuel-efficient would receive more allowances if allowances were allocated in proportion to fuel input). The costs of the allocation rule is also directly affected by the cost of collecting the information on which the allocations are based. The issue of information collection costs was not investigated quantitatively for this report.

⁴A permanent system is also known as a *historical* or *grandfathered* system.

⁵An updating system takes on the characteristics of a permanent system under some circumstances. For example, as the length of time between updates increases, an updating system becomes more like a permanent. Also, as firms receiving allowances place less weight on the future (i.e., they discount the future more), an updating system becomes more like a permanent system.

C. The recipients of the allocation

The policy options being considered involve allocating the allowances to either fossil fuel generators alone or to both fossil and non-fossil fuel generators. Because NO_x allowances are used to cover emissions of NO_x from the burning of fossil fuel, only fossil fuel burning generators will need to use them. The allowances allocated to generators that use no fossil fuel, then, can be expected to be sold to the fossil fuel users (or transferred to fossil units with the same owner).

D. The “core” allocation rule options

With three pairs of alternatives, eight ($=2^3$) potential allocation rules exist:

- i. Updating - fuel input - fossil fuel generators only
- ii. (Updating - fuel input - fossil and non-fossil fuel generators)
- iii. Updating - electricity/thermal output - fossil fuel generators only
- iv. Updating - electricity output - fossil and non-fossil fuel generators
- v. Permanent - fuel input - fossil fuel generators only
- vi. (Permanent - fuel input - fossil and non-fossil fuel generators)
- vii. Permanent - electricity/thermal output - fossil fuel generators only
- viii. Permanent - electricity/thermal output - fossil and non-fossil fuel generators

However, because non-fossil fuel generators do not use fuel inputs in the same way that fossil fuel generators do, using fuel input as the metric for allocating allowances to both fossil and non-fossil fuel generators is problematic. Hence, options (ii) and (vi) are not being considered (indicated by parentheses), thereby reducing the core options from eight to six alternatives.⁶

All six of the “core” alternatives are assumed to begin with an allocation for the year 2003 (the first year that, under the proposed section 126 rules, the limit for the ozone season would be in place). This allocation will be announced a minimum of three years before the beginning of the 2003 ozone season, and will be based on plant-specific activities during some historical period (e.g., an average of input or output during the years 1995, 1996, and 1997). For the three permanent allocation alternatives, this initial allocation is not updated, and units built after the historical period on which the allocations are based are assumed to get no allowances.

For the three updating alternatives, new units are assumed to be included in the allocations. Initially, the new units must be treated separately from the existing units, because there will be no historical data on which to base their allocations. Instead, the new units are assumed to be allocated

⁶A detailed examination of the six core options and three other options, which was submitted to ARD in a memorandum dated February 17, 1999, is attached as Appendix A.

enough allowances to emit at the same average rate as the rest of the industry until they have accumulated enough data to be considered “existing” units, at which point they are treated the same as all other units. (In allocating allowances to existing units, a portion of the total is assumed to be set aside for the new units.)

The initial historically based allocation for the updating alternatives is assumed to be held constant for 2003, 2004, 2005, and 2006.⁷ Starting in 2007, the allocations are assumed to be updated based on unit-by-unit activities four calendar years earlier. In most of the analysis presented below, it is assumed that this updating process takes place annually, though longer periods could also be used. This updating schedule makes it possible for operators to know a minimum of three years in advance what their allocations will be: at the end of the 2003 ozone season, EPA will announce allocations for the ozone season beginning in 2007.⁸

Many variants of these core alternatives are possible, and some of the possible variants are examined toward the end of this report. One significant variant was based on alternative iv shown above (that is, updating on the basis of output to all units), but updating quadrennially instead of annually. In this variant, the initial allocation would remain fixed until 2007, at which point a new allocation would be made based on each unit’s average output for the years 2000, 2001, 2002, and 2003. This allocation would then remain in place until 2011, when a new allocation based on 2004 through 2007 would go into effect.⁹

EPA also considered various ways of treating new units under the updating alternatives, including limiting their allocations to a rate no higher than their permitted emission rates, which can be much lower than rates for existing units. Finally, EPA considered an option equivalent to the

⁷It would also be possible to begin updating as early as the second year of program, using a different base year for each successive allocation.

⁸The non-ozone season months should provide enough time to collect and analyze the data on input or output, to calculate each unit’s share of input or output, and to compute the number of allowances it will be allocated for the future. If more time were needed, it might be necessary to leave more years between the base year and the year for which the base year determines the allocation..

⁹Quantitative results for this variant were interpolated from explicit analyses of similar options, and discussed in Section VII.C.

permanent alternatives, in which progressively more allowances are held back and auctioned to the highest bidder

IV. Supply and Demand Analysis of Effects of Options

Basic supply and demand analysis, as introduced in Section II, can be used to explain how the core allocation rules affect the electricity market. Figure 2 shows the reference case (as defined above) in which the equilibrium price of electricity is P_1 and the equilibrium quantity is Q_1 . This equilibrium represents the market outcome after the imposition of a new NO_x emission controls and a cap-and-trade system, in which the allowances were initially sold (e.g., through an auction) by the government.

Suppose, now, that the allowances (in an amount equal to the size of the cap) are distributed free to producers instead of being sold. Under a permanent allocation system, this distribution is made once and for all (on the basis of historical output or fuel use, or some other basis), and nothing that the electricity producers do after the system is in place will affect that allocation.¹⁰

An important question is whether changing from an allowance sale to a free, permanent allocation would change the effects on the market laid out in Figure 2. It might be thought that, if the suppliers were given a sufficient number of allowances at the start of the program, such that they would not have to purchase additional ones in the market in order to cover the incremental emissions from an increase in output, that the supply curve would not shift upward as much as in the reference case. Economic theory, however, strongly suggests that the supply curve will shift up just as much whether the allowances are initially sold by the government or are allocated at no charge. The reason that the need to surrender allowances will shift the supply curve upward whether or not they were given out free is that the allowances have the same market value in either case, *and can be sold if they are not used*. Giving up allowances that could be sold for \$2.50 will reduce a producer's net profit by just as much whether or not they cost anything initially – for the same reason that inherited gold sells for the same price as gold that is earned. In the terminology of economics, there is an “opportunity cost” of using allowances even if they were acquired for free, because in using them their owner loses the opportunity of selling them.¹¹

¹⁰The allocation can change over time (e.g., shrinking by some percentage every year) and still fall under the definition of permanent so long as these changes are all specified in advance, and do not depend on the actions of the affected industry.

¹¹Even if allowances are initially given out free in an amount that lets producers emit at 0.15 lbs/mmBtu, the need to surrender valuable allowances still causes the supply curve to shift up substantially. This would not be the

If a permanent allowance system shifts the electricity supply curve in the same way that it is shifted in the reference case, it follows that its effects on the market are the same as those shown in Figure 2. The equilibrium price will rise by the same amount, and the quantity of electricity produced in the 20 jurisdictions will be reduced to the same degree. According to theory, assuming that the market for allowances works smoothly, this similarity in market impacts will hold however the permanent allocation is determined: in proportion to historical electricity sales, historical capacity, historical fuel input, or any other system. This (perhaps surprising) conclusion is based on the “once-and-for-all” nature of permanent allocations. If nothing that producers do after the allocation affects the number of allowances they are given for free, then there are no differences from one permanent allocation option to another in their economic incentives once the program is in place. If the producers’ incentives are the same under every permanent allocation option, then they will act the same, and prices, quantities, generation mixes, and other factors will be identical.¹² It is true that different ways of allocating free allowances will help or hurt different firms, making them appear more or less profitable depending on how many allowances they are given. Any extra profits, however, would be seen as a one-time windfall rather than as a sign of the kind of fundamentally higher productivity that would encourage greater investment and expansion.

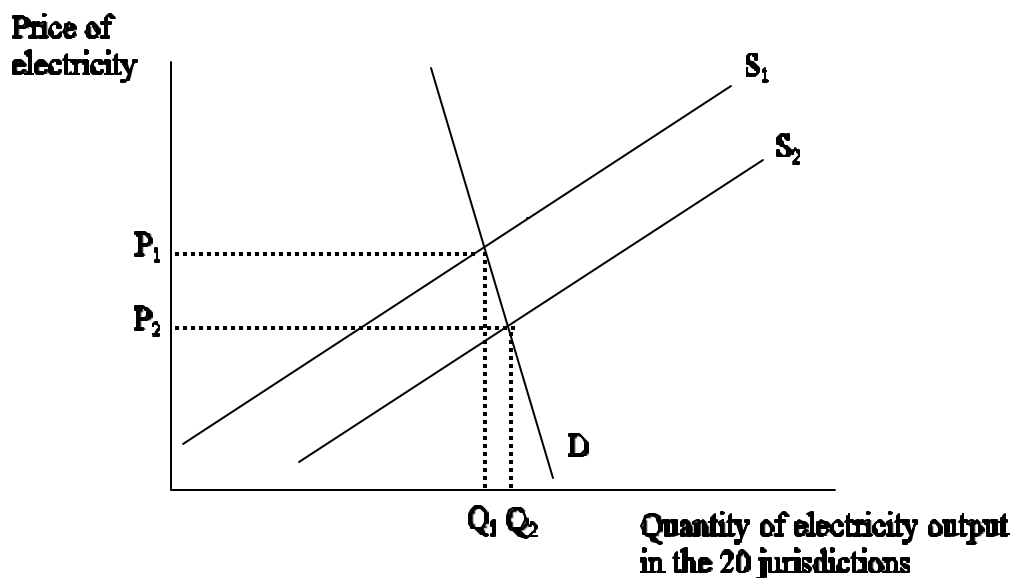
case if the supplier could not keep the extra allowances if the incremental power were not produced—which is an important observation to be covered further on.

¹²The conclusion that “once and for all” allocations based solely on the past should not affect future decisions is well supported by specific analyses of allocation mechanisms and by general economic theory. As an example of an analysis specifically aimed at allocation mechanisms is Jensen and Rasmussen’s “Allocation of CO₂ Emission Permits: A General Equilibrium Analysis of Policy Instruments” (Working Paper. Ministry of Business and Industry: Copenhagen, 1998). This paper examines several methods of allocating allowances in the context of a CO₂ permit system. They note that under a once-and-for-all allocation scheme, the costs or benefits associated with the initial allocation of allowances are “sunk.” Thus, these sunk benefits should not play a role in a firm’s subsequent output decisions regardless of the initial distribution of allowances. A more general view of this issue is found in the introductory text by Dornbusch and Fischer (*Economics*. McGraw-Hill: New York, 1983.) The authors cite on page 180 the example of a firm that is halfway through building a bridge when it discovers that the second half of the bridge will cost four times as much as the half already built. In trying to decide whether to finish the bridge, they state that the firm should not consider the cost of building the first half of the bridge because those costs have already been incurred. A firm that considers its sunk costs when deciding how much to produce has fallen prey to the sunk-cost fallacy and is not maximizing profits. In the bridge-building example, this is equivalent to the firm deciding that since it has already spent so much money to build the first half of the bridge it might as well finish the project. The equivalent fallacy in the case of allowance allocations might be a firm that had been given allowances based on an unprofitable plant’s *past* operation. If the allowance allocation was not contingent on the continued operation of the plant, and yet the firm kept the plant in operation on the grounds that the allowances allowed it to break even, the firm would not be maximizing its profits: it could actually do better by shutting the plant down and selling the allowances. Numerical examples of similar situations are presented in Appendix B.

Updating allocation systems differ markedly from permanent systems in that they affect producers' incentives. As under any other cap-and-trade allowance system, the supply curve is shifted up by the need to cover the incremental costs of NO_x control, *and* by the need to surrender valuable allowances for every additional unit of output (because of the extra emissions associated with each unit of output) from NO_x-emitting generators. Thus, up to this point, the effects of an updating system would be the same as shown in Figure 2.

The difference between updating and permanent systems derives from the linkage between the actions of the producers and the numbers of allowances they receive in subsequent periods. If, for example, operators know that producing one more MWh of electricity will lead to being granted an

Figure 3: The market for electricity with an updating allocation system



additional 1.5 lbs of allowances in the next year, they will immediately look more favorably on producing more electricity. Their reasoning might be as follows: "If I produce one more MWh of

electricity, the cap-and-trade program means that I will have to spend (in addition to the cost of fuel and maintenance) perhaps \$0.70 on urea for running my SNCR system, plus \$2.50 for 1.5 lbs of allowances this year to cover the incremental emissions of the source. These two factors together make me unwilling to produce another unit unless the price rises by at least \$3.20/MWh. But if I do produce another MWh, I will increase the number of allowances I get next year by 1.5 lbs, which will be worth perhaps \$2.50 next year. The \$2.50 I get next year does not completely make up for the \$2.50 I give up when I surrender the allowances this year, due to the time value of money. Still, the net cost of producing another MWh of electricity is much lower if I can count on getting a valuable extra allowance allocation than if I cannot.” By this reasoning, an updating system that joins future allocations to current production will result in a much lower supply curve than would be seen under a permanent allocation system; producers will be willing to supply the same amount even if the price does not rise as much, because of the incentive they get from the updating allowance allocation. (Similar reasoning applies whether the additional allocations come as a result of greater output or greater input, because greater input tends to result in proportionately more output.)

By inducing electricity generators to increase fuel input use or electricity output, therefore, updating systems encourage electricity production and shift the market supply curve down. This supply curve shift is shown in Figure 3 as the change from S_1 to S_2 . With the change in the supply curve comes a change in the market equilibrium: there will be a lower equilibrium price (P_2) and higher equilibrium quantity (Q_2) of electricity produced in the 20 jurisdictions as a result of updating feature of the allocation system.

The magnitude of the shift in supply may vary with the specifics of the updating allocation system. Because an output-based system directly rewards increased output, it can be expected to have more effect on supply than a system based on input, which encourages output only indirectly. Among output-based systems, the effects of allocating to both fossil and non-fossil fuel sources, relative to allocating to fossil fuel sources only, depends on how sensitive these two types of sources are to price changes. As will be explained in Section VI, because the non-fossil supply appears to be quite inelastic (that is, insensitive to price changes), the industry-wide supply curve is shifted more if all allowances are allocated to the fossil-fueled sources.

B. Comparing allocation rules using numerical simulations

As already noted in the previous discussion, the distribution of allowances among electricity producers will vary depending on the allocation rule chosen. To get a better sense of this distribution, EPA determined that it would be useful to estimate the magnitude of the allowance transfer to several

common generator types. For each of the six core allocation options, therefore, EPA directed ICF Consulting to create a spreadsheet model to estimate the allowance allocation to, and the economic implications for, a range of representative technologies: (1) conventional pulverized coal (existing coal); (2) gas combined cycle; (3) simple gas turbine; and (4) nuclear.¹³ Incremental benefits were also estimated for a coal unit that was not yet in existence until after the establishment of the allowance allocation system. Hypothetical plants were used in the model, with inputs typical of the performance characteristics for each type.

In the spreadsheet model, we created a scenario representing each hypothetical unit's output over time (based on the characteristics assumed for it). We then calculated what fraction of the total fuel input, electricity output (fossil or total) each unit represented. Given these fractions, the total number of allowances available for allocation, and rules for allocating allowances under different options, we calculated how many allowances each unit would be awarded in each year. The values of these allowance allocations were then calculated by multiplying the numbers of allowances by estimates of the marginal cost of NOx reductions from EPA's analysis of the section 126 rules as proposed on October 21, 1998. The value of the allowances received in each future year were then discounted back to the first year of the program (assumed to be 2003) and summed to determine the net present value of the allocations.

This process was then repeated under slightly different assumptions about the level of operation of each unit. For example, we assumed that one of the hypothetical plants increased its electricity output by a single MWh in the year 2003, and recalculated the net present value of all of the allowances it would be allocated in future years. By comparing the present values of the streams of allowances with and without the one MWh change in output, we found the marginal allowance-related benefits per unit of output. These marginal benefits are shown in Table 1 for individual plants of different generation types under the six core allocation options.

¹³ See Appendix A.

Table 1: Marginal benefit of producing an additional megawatt of electricity output in terms of the value of allowances earned (US 1990 \$/MWh), for allowances allocated from 2003-2013 to representative plants, by generation type (assumed lag = 4 years)

Allocation Option	Existing Coal	Nuclear	Combined Cycle	Turbine	New Coal
Updating/Input/Fossil	\$2.17	-	\$1.82	\$2.20	\$4.36
Updating/Output/Fossil	2.26	-	2.26	2.26	4.71
Updating/Output/All	1.76	1.76	1.76	1.76	4.21
Permanent/Input/Fossil	-	-	-	-	-
Permanent/Output/Fossil	-	-	-	-	-
Permanent/Output/All	-	-	-	-	-

The marginal benefits in the table imply that the incentives to increase electricity output for a given generation type and option can vary relative to other generation types and options. As shown in the table, the incentives are seen only for updating systems: under permanent systems, increases in current output have no effect on future allocations, and therefore result in no incremental incentive.¹⁴ The incentives provided by the output-based options are the same for all of the existing fossil fueled types – \$2.26/MWh or \$1.76/MWh – with the higher incentive for the option that limits the allocations to fossil units. The reason that the incentives are the same under the output-based options is that table presents the value of the incentive per unit of output, and the allowances are also allocated per unit of output. If all existing sources are given the same number of extra allowances per unit of output, then the value of these extra allowances will be the same per unit of output as well. The nuclear unit, because it does not use fossil fuel, is given no incentives except in the option in which allowances are given on the basis of output to all sources.

The incentives provided by the input-based allocation option vary from type to type, and are substantially lower for gas combined cycle units than for conventional coal or simple gas turbines. This

¹⁴This point is discussed in Note 12. See also Appendices B and C for discussion of the potential effects of a single permanent allocation, and a series of permanent allocations, on incentives to increase output .

result is related to the fact that combined cycle units are more energy efficient, using a smaller quantity of energy (input) for each incremental MWh (output). As a result, their share of total inputs, and thus their share of allowances, rises substantially less with output than does the share for less efficient types.

For the updating system based on output for fossil fuel units, Table 1 shows a stronger incentive to increase output for new plants. This somewhat surprising result is due to the assumptions made about the number of allowances received by units before they have built up a history of inputs or outputs used in updating the allowance allocation. New plants were assumed, based on EPA's proposed allocation system, to be given allowances based on their current operations until they have built up enough of a history for their allowances to be based on their past operations. This simple assumption means that their operation in their first few years affects their allocations twice: in the current period, and in a future period. The net incentive effect is therefore about twice as large in the early years of a new plant.

Different ways of treating new units could have very different effects on new unit incentives, however. If new units were given no allowances until they had been in operation for several years, or if the new units were given allowances only at the rate they were permitted to emit, or if they were given only a fixed number of allowances based on their capacity and type, the incentives for operating the new units would be smaller than shown. The exact characteristics of an option as it relates to new units should therefore be specified and analyzed in detail.

The overall magnitude of the incentives is substantial in comparison with the marginal cost of generation, which averages around \$17-25 per MWh. Because these incentives apply only to units within the 20 jurisdictions (since units outside of the region are excluded from the allowance system and its requirements), they can have substantial effects on the choice of where to generate electricity.

V. Economics issues

A. The distributional effects of the allowance allocation system and rent seeking

When allowances with market value are being allocated to producers at no cost, the recipients receive a substantial economic benefit. Which producers receive allowances, then, becomes an important distributional question. The answer to this question depends, in part, on all three of the basic elements discussed above. The choice of a system type (updating or permanent), though, is of particular importance because it determines whether the value of the allocated allowances will be shared between producers and consumers of electricity. The connection between updating and the distribution of the value of the allowances between producers and consumers is discussed below.

In a permanent allocation system, the benefits of the free allowance allocation are shared among the producers of electricity alone, with the distribution determined by the other allocation rule features such as whether the allowances are allocated according to fuel input or electricity output, and whether owners of non-fossil fuel units receive some of the allowances.

In an updating allocation system, benefits of the free allocation are received by consumers, as well. The way that the consumers share in the benefits is shown in Figure 5. In the figure, P_1 and Q_1 indicate the initial equilibrium price and quantity in the market for electricity *after* the imposition of new NOx regulations that require additional emission controls, but before considering the effects of updating (as shown in Figure 2). Although producers benefit from this allocation because allowances are obtained at a zero price, consumers also benefit because the updating system itself encourages producers to increase supply, which in turn lowers the price of electricity. This secondary transfer to consumers occurs through the electricity market's pricing mechanism and not through a direct government transfer (as is the case in the transfer to producers).

The key factor in this benefit transfer mechanism is the updating system itself, which causes producers to modify their production decisions. By inducing producers to increase supply, as noted by the shift from S_1 to S_2 in Figure 5, the updating system helps consumers by lowering the price.¹⁵ The resulting reduction in the price of electricity completes the transfer to consumers by increasing consumer surplus (shown in Figure 5 by the cross-hatched area).

¹⁵The magnitude of the shift in supply from S_1 to S_2 is comparable to the distance between S_1 and the dashed line shown in Figure 2 when producers do not discount the future. As the rate at which the future is discounted increases, the magnitude of the shift from S_1 to S_2 decreases.

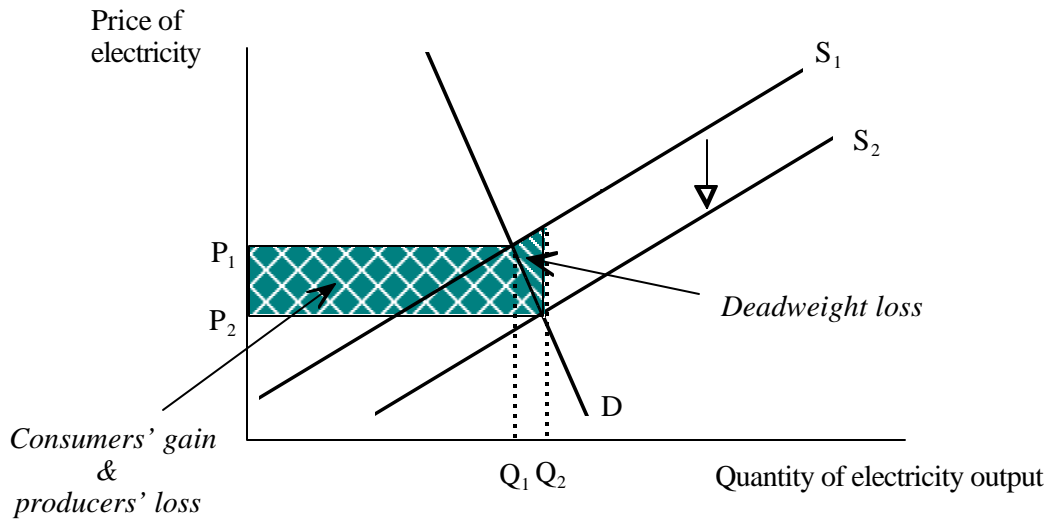
The higher level of electricity production can lead to *economic inefficiency*. Inefficiency in this context is a somewhat subtle concept that refers to outputs that cost more to produce than they are worth to consumers. Assuming a competitive electricity market, any electricity produced in excess of Q_1 costs more to produce than consumers are willing to pay (i.e., the marginal cost is greater than the marginal revenue). This excess production is an inefficient or wasteful use of resources, which economists call a “deadweight loss.” The magnitude of this loss is shown by the area of the striped triangle in Figure 5.^{16 17}

¹⁶For analysis and discussions on the efficiency aspects of updating systems., see Fisher, Carolyn, “An Economic Analysis of Output-Based Allocation of Emission Allowances,” document prepared for meeting of the Greenhouse Gas Emissions Trading Braintrust, Nov. 24-25, 1997 (affiliated with Resources for the Future); Ellerman, A. Denny, “Note on Allowance Allocations Based on Current Output,” unpublished manuscript, Oct. 2, 1998; Sterner, Thomas, and Lena Höglund, “Output-Based Refunding of Emission Payments: Theory, Distribution of Costs, and International Experience,” unpublished manuscript, Mar. 1998; Wade, Sarah M., and Joseph Goffman for the Environmental Defense Fund, Comments on Federal Implementation Plans to Reduce the Regional Transport of Ozone; Proposed Rule EPA Docket No. A-98-12 and Findings of Significant Contribution and Rulemaking on Section 126 Petitions for Purposes of Reducing Interstate Ozone Transport; Proposed Rule EPA Docket No. A-97-43, undated-1998/9; Lashoff, Daniel A., Tim Hargrave, and Sam Keller, “Output-Based Allocation of Emission Allowances,” discussion draft, affiliations: Lashoff – Natural Resources Defense Council, Hargrave and Keller – Center for Clean Air Policy, October 1997.

¹⁷It is also worth noting that the deadweight loss triangle associated with the updating system is conceptually related to the rent seeking activity associated with the permanent system. In the classic rent seeking case, potential beneficiaries of valuable government transfers lobby government to direct the transfer their way. Lobbying activity related to the initial allocation of allowances in a permanent system is consistent with this paradigm. However, with an updating system, the channel through which rent seeking behavior occurs is different. Rather than lobby government officials directly to induce them to choose the metric that gives them the greatest chance at earning future allowances., rent seekers pursue these rents through their market behavior, specifically, by doing more of the activity that earns them future allowances (e.g., increased fuel input use or electricity production)

Although the channels are different, the fundamental inefficiencies of rent seeking are present with both allocation systems. Principally, the net gain to society could be increased by reducing the duplicative costs incurred pursuing the transfer. Minimizing the social welfare loss associated with the free transfer of allowances involves choosing between a permanent system in which rent seeking activity is concentrated in the rule-making period, and an updating system in which rent seeking activity is spread out in time, beginning with the rule-making period and carrying forward to all periods in the future that effect future allowance allocations.

Figure 5: The effect of an updating allocation system on social welfare



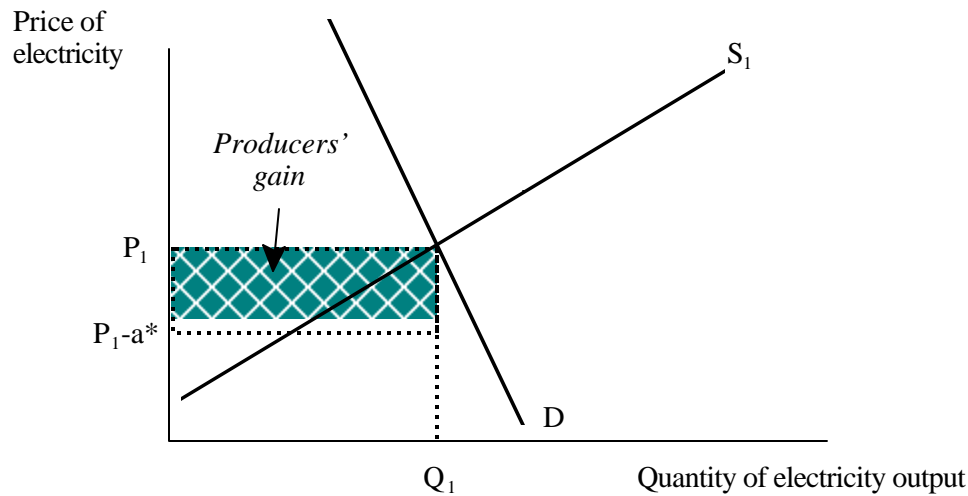
The distributional issues associated with both a permanent system and an auction can also be shown graphically. First, note that with an auction or a permanent system, there is no inducement to increase supply as there is with an updating system, implying that the electricity market equilibrium price and quantity remain at P_1 and Q_1 , respectively.

The producers' benefit from the free distribution of allowances through a permanent system can be shown by simply computing the average value of allowances per unit of electricity output (a^*) and multiplying it by the quantity of electricity output. This area is shown in Figure 6. The transfer has no impact on the firm's output decision. However, over the long run it may yield gains in productivity if it is used for research and development or to finance capital investments. Therefore, the transfer may shift the firm's long-run supply curve, but because the transfer is not linked to any specific actions on the part of the firm, it is not clear what the result will be. For example, the transfer could be used by the firm to boost dividend payouts to shareholders, or to enhance employee compensation, as well.¹⁸

¹⁸The outcome of an auction is fundamentally different because, by definition, the transfer of allowances is made at a positive price. Producers still gain through an auction when their willingness to pay exceeds the allowance

In conclusion, the choice between a permanent system, an updating system, and an auction involves a potential trade-off involving the distribution of the benefits of free allowances and the avoidance of inefficiency in electricity production. A permanent system can help minimize electricity

Figure 6: The producers' gain with a permanent allocation system



production costs and ensure that electricity is not overproduced, but it confines the benefits of the free allowance allocation to the producers of electricity. With an updating system, the benefits of the free allowance allocation are shared between producers and consumers of electricity, but electricity production is somewhat inefficient (i.e., too costly to produce relative to its value to consumers).

B. Revenue-recycling and tax distortions

price (which is the case for all allowances purchased through an auction except the marginal unit), but the gain is smaller than when the allowances are allocated for free through a permanent system. This can be demonstrated by using the graph in Figure 6 by simply noting that a smaller a^* implies a shorter, but equally wide, shaded rectangle.

An important focus of the economics literature has been on the interaction of the allowance allocation rule on the tax system.¹⁹ The literature focuses on two fundamental interactions: the revenue-recycling effect and the tax-interaction effect.

The *revenue-recycling effect* refers to the improvement in the economy's operation functioning resulting from the use of revenue collected from an auction or an environmental tax in place of revenue collected from a distortionary form of taxation, such as an income or a sales tax. The incentive to generate this "double-dividend" is based on the principle that distortionary forms of taxation promote inefficiency. (Inefficiency refers to the misuse of economic resources, as when they are used to produce outputs that are not worth to enough to consumers to outweigh their costs.) By substituting an alternate source of tax revenue that does not promote inefficiency, therefore, is welfare enhancing. Because an environmental tax or auction is not inefficient (the tax or auction price alters behavior in a socially desirable way), it can be used as a revenue generating source without the adverse behavioral change that is the source of the inefficiency.

The *tax-interaction effect* refers to the impact that a higher electricity price has on labor markets already plagued by distortionary income taxation.²⁰ Specifically, the higher electricity price magnifies the adverse effect of the income tax on individuals' willingness to work (i.e., supply their labor). The intuition goes as follows: (i) At the margin, income taxation reduces individuals' desire to work because it decreases the after-tax wage. Society is harmed by this because people produce less work output and instead substitute leisure. (ii) Producers of goods that require the disposal of pollution and thus pay the cost of buying allowances and increasing control are able to pass on some of these higher costs to consumers. Consumers of these "pollution intensive" goods reduce their purchases of these goods because the price is higher, and instead substitute leisure (as well as non-pollution intensive goods). (iii) By increasing the price of pollution intensive goods, the distortion toward too much leisure

¹⁹See, for example, Jesper Jensen and Tobias N. Rasmussen, "Allocation of CO₂ Emission Permits: a General Equilibrium Analysis of Policy Instruments," unpublished manuscript, December 21, 1998; Peter Cramton and Suzi Kerr, "Tradeable Carbon Permit Auction: How and Why to Auction Not Grandfather," *RFF Discussion Paper* 98-34, 1998; Carolyn Fischer, "An Economic Analysis of Output-Based Allocation of Emission Allowances," - document prepared for meeting of the Greenhouse Gas Emissions Trading Braintrust, No. 24-25, 1997 (affiliated with RFF); Fischer 1999; Lawrence Goulder, Ian W. H. Parry, and Dallas Burtraw, "Revenue-Raising vs. Other Approaches to Environmental Protection: The Critical Significance of Pre-Existing Tax Distortions," *RAND Journal of Economics*, 28(4) 1997, 708-31; Don Fullerton and Gilbert Metcalf, "Environmental Controls, Scarcity Rents, and Pre-Existing Distortions," *NBER Working Paper* 6091, July 1997.

²⁰The price of electricity is assumed to increase in response to stricter NO_x regulations that require more control strategies in the aggregate.

is increased. Thus, by adding a new adverse distortion to a pre-existing adverse distortion, the new regulatory rule exacerbates an already inefficient situation. The impact that each effect has on the overall economy depends on the system for allocating allowances. Under a *permanent* system, there is no revenue recycling because no revenue is collected by the government as part of the allocation. It does have an adverse tax-interaction effect, though, because the price of electricity is higher following the implementation of a trading program that internalizes environmental costs. An *updating* system also does not have a revenue-recycling effect. However, it has a tax-interaction effect for the same reason that a permanent system has one, yet because updating causes electric utilities to increase output, pushing the price of electricity down, the magnitude of the tax interaction effect is smaller. Put differently, the rise in electricity prices resulting from the new NO_x program cost is smaller, since it is offset, in part, by the increased supply of electricity attributable to the incentives caused by the updating system. Thus, an adverse tax-interaction effect may exist, but it is smaller as a result of updating.²¹

D. Imperfect competition²²

If there exists market power in the electricity market, which is likely until deregulation generates competition, then electricity output may be inefficiently low (in that the value to consumers of additional electricity would be more than the cost of producing it). The increase in output resulting from an updating system may therefore increase net social welfare by inducing producers to aim for a less inefficient level of output (at least until the market becomes competitive).

VI. Allocations to non-fossil generators

As noted above, one of the core allocation options considers allocating allowances to non-fossil generators. This allocation can be expected to give increased incentives for non-fossil generation, while reducing the incentives for fossil units (because allocating some of the allowances to non-fossil units

²¹An *auction* has both a revenue-recycling effect and a tax-interaction effect. Because they affect social welfare in opposing directions, the adverse tax-interaction effect is at least partially offset by the beneficial revenue-recycling effect. For a further discussion of this subject, see Goulder, Lawrence H., Ian W.H. Parry, and Dallas Burtraw (1997), "Revenue-Raising Versus Other Approaches to Environmental Protection: The Critical Significance of Preexisting Tax Distortions," *RAND Journal of Economics*, 28(4), 708-731.

²²For a more complete discussion, see: Henry van Egteren and Marian Weber, "Marketable Permits, Market Power, and Cheating," *Journal of Environmental Economics and Management*, 30, 1996, 161-173; Cathrine Hagem and Hege Westskog, "The Design of a Dynamic Tradeable Quota System Under Market Imperfections," *Journal of Environmental Economics and Management*, 36, 1998, 89-107.

would leave less for the fossil units). The net effect on generation of this shift in incentives depends on how responsive these two types of generation are to changes in incentives.

The responsiveness of non-fossil sources can be expected to be much lower than that of the fossil sources. The reasons to expect that non-fossil sources will not respond strongly to allowance-based incentives can be divided into those relating to the level of operation of ongoing units, and those relating to the closure of old units and the creation of new ones. Non-fossil units tend to have low variable operating costs, ranging from the relatively low fuel costs for nuclear units to the free wind, sunshine, and running water used by renewables. Because the operating costs of the non-fossil units are generally lower than those of fossil fuel units, it makes economic sense for these units to be run as much as possible once they have been built, whether the revenues received for their electricity are high or low. The model used by EPA to estimate the effects of the section 126 rules (IPM) therefore assumes that the non-fossil units' operation is not affected by electricity revenues. For the same reason, the incremental incentives from the allowance allocation mechanism can be expected to have almost no effect on the day-to-day output decision of the non-fossil units. Many fossil units, on the other hand, are in operation only part of the time, and can increase or decrease their output rapidly if economic circumstances change. In the short run, therefore, taking some of the allowance allocations away from fossil units to give to non-fossil units will reduce the net effect of allowances on output.

Whether the availability of allowances would affect the non-fossil supply of electricity in the long run, once operators have had time to adjust capacity through new builds or retirements, is a separate question. ICF Consulting examined the long-term effects of allowance allocations on both nuclear and renewable capacity, though with the greatest emphasis on potential to slow the shut-down of existing nuclear plants.

A. Analysis of the Effects of Allowance Allocations on Nuclear Capacity

Allowance allocations have at least some potential to change the decision of when to shut down existing plants. By receiving valuable allowances, units that are otherwise in a financially tenuous condition might be made well enough off that they are able to remain in operation. Assuming that a generator shuts down if the present value of all future earnings is negative, the question becomes whether allocating allowances to non-fossil fuel generators creates a transfer that keeps the present

value of future earnings positive when they would otherwise be negative.²³ ICF Consulting conducted several analyses to determine the impact of an annually updated output-based allocation system on the shutdown decisions of nuclear units.

Based on projections by the Energy Information Administration (EIA), ten nuclear units were identified in the 20 jurisdictions that would retire prior to the expirations of their licenses due to financial losses. Our analysis investigates whether the NO_x allowances, if allocated to these nuclear units, would alter their early retirement decisions. We collected performance data for each of these ten nuclear units, as well as data resulting from electricity market forecasts by IPM and other sources. The analysis uses a NO_x allowance allocation spreadsheet model, with inputs of unit-specific data. The production cost and revenue streams are calculated for each unit, with net cash flows estimated between 2001 and the years that licenses expire. The itemized revenues included capacity revenue and proceeds from the sale of energy sales and NO_x allowance. Itemized costs encompassed variable and fixed O&M costs and fuel costs.

The ten plants vary in their apparent profitability, and therefore, in the likelihood that they will continue to operate if they receive no allowance allocation. The unit's capacity factor (CF) is a key element in determining the financial situation of a plant. We found that the contribution of the revenue from selling NO_x allowances to the plant's overall revenue stream (approximately 18 percent of the net cash flow for the average plant in this group) has a minimal impact on each plant's profitability, and thus has only a slightly positive effect on the probability a unit will not shut down. Put another way, the revenue from allowances is usually not large enough to offset the larger gap between operating revenues and costs.

The determination of the impact of allowances on profitability centers around the capacity factor of each plant. Under the assumption that each plant's future capacity factor can be predicted exactly, and that it will be equal to the average capacity factor at the plant in the past, the conducted by ICF Consulting for this report showed that one plant (Peach Bottom #2) would remain barely profitable for four more years than if it received no allowances. In all other cases, plants that would have been unprofitable without allowances would still be unprofitable with allowances.

²³Such an allocation would apply only if an updating system is used that is based on electricity output. Under a permanent system, the allowances would be treated as a "sunk benefit," implying that the decision to shut down would be made independent of the allowance transfer (see note on page 12, and Appendix B, for discussions of sunk benefits). Because nuclear units do not use fossil fuel, they would not be included in a system based on heat input.

Because future capacity factors are uncertain and the views toward that uncertainty are likely to vary among plant operators, ICF Consulting conducted two analyses that introduce uncertainty into the model. In a Monte Carlo analysis, capacity factors at each plant were allowed to take on random values based on past variability in capacity factors *at that plant*. Similarly, in a second analysis, capacity factors at all plants took on random values based on the past variability of capacity factors *at all plants*. The results of these analyses were quite similar and consistent with the initial analysis: receiving free allowances might save one or two plants, but it was even more likely that none would be saved.

To provide a consistency check, the results of the three analyses conducted for this report were compared to an analysis conducted by EIA on the effects of the Kyoto Protocol on nuclear plant closing. In that analysis, different levels of carbon reductions were projected to raise electricity prices by varying amounts, which, in turn, would lead to reductions in nuclear plant closures. By translating the value of NO_x allowances into their equivalents in terms of changes in electricity prices, it could be estimated that EIA's method would have shown roughly a one percent increase in nuclear generation by the year 2015 in response to the allocation of additional allowances to nuclear units. Though this comparison is quite rough, it appears to comport well with the order of magnitude of effects projected by ICF Consulting's analyses of threatened plants. In its analysis of the effects of allowance allocations, therefore, ICF Consulting assumed that allocating allowances to nuclear units would not change the number or rate of nuclear plant closures.

B. Potential Effects of Allowance Allocations on Renewable Generation

ICF Consulting did not conduct an independent analysis of the long-run supply of renewable generating capacity and the effects of allowance allocations on that capacity. Instead, we consulted three existing studies of the effects of carbon policies on renewable generation. Because policies to reduce carbon emissions tend to give a financial advantage (e.g., through an increased price of electricity) to renewable sources, renewable sources are projected to increase their share of total generation in carbon-reduction scenarios. For each study, we found the projected market share increase for renewables and the increased financial incentive that was associated with it. We then compared the carbon-related incentives in the studies to the magnitude of NO_x allowance benefits. Under the assumption that increases in market share would be proportional to the magnitude of the incentive, we were then able to estimate the market share increase for renewables that could be expected in response to granting allowance allocations to renewable sources.

The three studies that were identified as addressing the issue of the impact of electricity price increases on the market share of renewable electricity were the following:

- U.S. Department of Energy, Energy Information Administration (DOE/EIA), 1998, *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity*.¹
- Short, Walter, and Laura Vimmerstedt, undated, *Supply Curves for the Reduction of U.S. Carbon Emissions with Renewable Energy*, National Renewable Energy Laboratory.
- Interlaboratory Working Group, 1997, *Scenarios of U.S. Carbon Reductions: Potential Impacts of Energy-Efficient and Low-Carbon Technologies by 2010 and Beyond*. Oak Ridge, TN and Berkeley, CA: Oak Ridge National Laboratory and Lawrence Berkeley National Laboratory. ORNL-444 and LBNL-40533.

The results of the three studies were fairly consistent. They yielded projections that increasing the revenues of renewable sources by 3 mills per kilowatt-hour for five months each year (which is about the magnitude of the benefits of granting allowances to non-fossil units) would result in increased market share for renewable electricity of between 0.2 to 0.4 percentage points in the 2010 to 2020 timeframe. The small size of this impact led us to assume that renewable generation would be essentially insensitive to the allowance allocation mechanism.² In terms of the direction of the effects of allocating allowances to non-fossil units, though, it is reasonable to expect any added incentive to lead to a decrease in non-capped pollutants like carbon. In addition, because the renewables sector is currently small compared to the industry as a whole, even an increase in market share of a fraction of a percentage point could result in a significant percentage increase in the renewables industry in itself.

VII. Results of Simulations Using IPM

A. Approach to Using IPM

The supply and demand analysis of the effects of allowance allocations on the electricity market, combined with the spreadsheet analysis of the magnitudes of the allowance values, suggested that the different options could change the effects of the section 126 rule to a large enough degree to show up in the results of simulation modeling. ICF Consulting therefore set up IPM (the electricity generation simulation model used to estimate the costs of the section 126 rule) to recognize the effects of allowance allocations. As used, IPM calculates the number of allowances each unit would be eligible

¹ Internet address: <http://www.eia.doe.gov/emeu/plugs/plkyoto.html>

²Memorandum from William Driscoll to EPA, dated March 16, 1999.

to receive under specific options, considering that unit's fuel input and electricity output, and then computes the discounted value of those allowances given the estimated market price of allowances.³ These allowance values are treated by the model as offsets to the costs of operation, thereby leading the model to treat any incremental allowances as an incentive to produce more electricity.

A total of four model runs were used, simulating the production of electricity from 2000 through 2019 under an ozone-season cap on NO_x for the 20 jurisdictions. One run, termed the reference case, assumed that changes in generating unit operations would have no effect on allowance allocations. This run was used to represent all of the permanent allocation variants, as well as any potential options in which allowances are distributed through an auction or direct sales. (Differences across the permanent options, in the allowance profits or costs, can be computed off-line, but have no effect on the simulation model, for reasons discussed in a previous section.)

The other three runs simulated the updating options: fuel input-based updating for fossil units; electricity output-based updating for fossil units; and electricity output-based updating for both fossil and non-fossil units. In all cases, updating was assumed to be done annually, based on output or input from four years earlier.

As in all of the IPM runs conducted in support of the section 126, SIP call, and FIP rulemakings, both total demand for electricity and non-fossil capacity and generation were assumed to be insensitive to price changes. Off-line calculations (that is, outside of the IPM model) were made of the potential effects of price elasticity of demand on emissions. These off-line calculations were particularly important in estimating the effects of updating on carbon and mercury emissions; they are detailed in Appendix D.

For simplicity in programming the effects of updating, no special allowance set-aside or allocation was modeled for new units. New units were treated like existing units, in that for each year they were granted allowances for a future year, but were not given any special allocations in their first years based on *current* operations. This simplification means that the analyses conducted for this report understate both the incentive to operate new units in their early years, and (to a small extent) the

³The number of allowances each unit is given per unit of output or input cannot be determined before the model is run because of the limit (cap) on the total number of allowances. Instead, units are awarded a share of the total number of allowances based on their shares of total output or input. Because these shares are determined simultaneously with the decisions of all of the other units, it was necessary to use an iterative procedure. In the procedure, successively more accurate estimates of the allowances per unit of output or input were used to calculate per-unit incentives, until the model runs converged on a single solution.

attractiveness of building new units. Section VII.C. discusses this issue further.

B. Results of IPM Analyses

The results of the analyses of the updating options, both relative to the permanent allocation reference case and to one another, paralleled the predictions of the basic supply and demand analysis. Generation in the 20 jurisdictions was projected to be higher in the updating cases, and lower in the rest of the country, leading to virtually unchanged generation. (The lack of a noticeable change in national generation is a result of the simplifying assumption used in the IPM runs that electricity use is not affected by the policy options. This assumption was relaxed in off-line calculations, allowing updating to increase system-wide generation slightly. These off-line calculations are described in Appendix D, but the results are not shown in the tables in this section.)

Table 2: Change in electric generation (GWh) relative to permanent allocation
(These results exclude the effects of changes in total electricity use due to price changes)

20 Jurisdictions Updating Option		All Coal	Oil/Gas Steam	Combined Cycle	Turbine	Total
Input/Fossil	change	6,498	1,957	121,958	11,719	142,132
	%	0.5%	8.4%	109.7%	68.8%	10.5%
Output/Fossil	change	2,873	1,484	127,569	8,716	140,643
	%	0.2%	6.4%	114.8%	51.2%	10.4%
Output/All	change	2,007	1,154	126,881	2,803	133,175
	%	0.2%	5.0%	114.2%	16.5%	9.8%

Total System Updating Option		All Coal	Oil/Gas Steam	Combined Cycle	Turbine	Total
Input/Fossil	change	(9,365)	(1,202)	7,308	358	99
	%	-0.3%	-0.7%	1.4%	0.6%	0.0%
Output/Fossil	change	(9,725)	(1,967)	12,862	(1,083)	87
	%	-0.5%	-1.1%	2.4%	-1.7%	0.0%
Output/All	change	(9,922)	(1,514)	12,599	(992)	171
	%	-0.5%	-0.8%	2.4%	-1.6%	0.0%

Table 2 shows the effects of the options on generation by region, compared to the permanent allocation options. This table, and the ones that follow, show averaged results over the period 2004 through 2019. Total output of electricity rises by about 10 percent in the 20 jurisdictions under the updating options, with a slightly smaller increase in the Output/All option. This generation is shifted into the 20 jurisdictions from the rest of the system, as can be seen from the fact that the system-wide total barely changes at all (again, these analyses assumed that electricity usage would not be affected by the policies). This shift in generation comes about because the allocation of more allowances to units in the

20 jurisdictions gives those units an added incentive to generate.

It is important to note that little of this increase is from coal units, which constitute the majority of existing capacity. The largest increase is from gas combined cycle units, which are both low in emissions and relatively energy efficient. There is a somewhat smaller gain for gas combined cycle units, relative to the less-efficient types, under an input-based updating program. This pattern is to be expected, due to the greater incentive given to units that use more fuel under an input-based system.

Some of the increased generation in the 20 jurisdictions comes from increased output at existing units. Most, however, appears to come from a substantial increase in combined cycle capacity in the 20 jurisdictions under the updating options. Capacities of simple-cycle turbine units are also much greater in the 20 jurisdictions when compared to the reference case. As seen in Table 3, these changes result largely from shifts into the 20 jurisdictions from the rest of the system, not from a great increase in system-wide capacities. Still, as shown in the lower panel of Table 3, the updating options lead to a relative increase in gas combined cycle capacity, and a drop in coal, oil/gas steam, and simple-cycle turbines (except in the input-based option). One explanation for this shift may be the increased pressure to control emissions under an updating system: with more fossil-fueled generation, and more fuel input, the effective emission rate in pounds of NO_x per mmBtu would have to be lower if total NO_x emissions were capped. One way to reduce emission rates is to switch to inherently cleaner types of generation, and this may be one reason for the shifts in generation seen in the table.

The shift in capacity and generation into the 20 jurisdictions shift the costs of generation as well: with more units being built in the 20 jurisdictions and greater total output, costs in the 20 jurisdictions are greater by several billion per year. Total system-wide costs change by much less, because most of the cost increase in the 20 jurisdictions is due solely to a transfer from the rest of the country. There would, however, be some increase in net system-wide costs under the updating options, as shown in the last column of the lower panel of Table 4: input updating would add \$29 million per year to the cost of the section 126 rulemaking; output updating for fossil units would add \$27 million, while output updating to all units would add \$18 million.

Table 3: Change in capacity (MW) relative to permanent allocation

20 Jurisdictions Updating Option		All Coal	Oil/Gas Steam	Combined Cycle	Turbine	Total
Input/Fossil	change	89	66	34,933	25,067	60,152
	%	0.1%	0.3%	90.8%	52.8%	21.2%
Output/Fossil	change	(4)	390	36,095	20,389	56,869
	%	0.0%	1.7%	93.8%	42.9%	20.1%
Output/All	change	(4)	302	36,080	8,488	44,866
	%	0.0%	1.4%	109.3%	17.9%	12.7%

Total System Updating Option		All Coal	Oil/Gas Steam	Combined Cycle	Turbine	Total
Input/Fossil	change	(1,279)	(183)	1,078	391	7
	%	-0.4%	-0.2%	0.6%	0.4%	0.0%
Output/Fossil	change	(1,377)	(11)	2,218	(838)	(9)
	%	-0.5%	0.0%	1.7%	-0.9%	0.0%
Output/All	change	(1,378)	(97)	2,210	(736)	(1)
	%	-0.5%	-0.1%	1.3%	-0.8%	0.0%

The table shows that these increases are an insignificant portion of the total costs of generation. They are not, however, completely insignificant percentages of the costs of the 126 program as a whole: the annualized cost of the NO_x control program is estimated to be about \$1.25 billion under a permanent allocation system (in 1990 dollars), so the updating options would add in the range of two to three percent to costs.

The reason for this cost increase was discussed in Section V: economic inefficiency results if producers are encouraged (by offering the incentive of more allowances) to generate more electricity

beyond the point where their true costs exceed what consumers are willing to pay. The theoretical magnitude of the inefficiency was illustrated in Figure 5, as the shaded area between the true cost curve S1 and the demand curve, for the increased units of output from Q1 to Q2.

Another way to understand the origin of the increased costs due to updating is to consider the effects of increasing fossil generation within a capped region. As noted above, increasing the use of fuel in a region with a binding cap on NO_x emissions effectively tightens the standard in lbs/mmBtu. This tighter standard leads to higher control costs per unit, a fact that is reflected in the marginal costs of NO_x control under the updating options: marginal costs are higher by about ten percent as compared to the reference case.

As discussed, the incentives provided by updating allocation mechanisms shift the supply curve in the 20 jurisdictions downward, leading to noticeably lower equilibrium marginal costs. Assuming a competitive market for electricity, the price will shift down by the amounts shown in Table 5. Because retail electricity prices are higher than marginal costs (due to capacity values, transmission charges, and other factors), the percentage changes in prices seen by consumers would be smaller than the percentage changes in marginal costs. Still, as shown in the table, in most parts of the 20 jurisdictions, ozone season prices would be lower by several percent under the updating options.

Table 4: Change in total production costs (million \$) relative to permanent allocation

20 Jurisdictions		Variable	Fixed	Fuel	Capital	Total
Updating Option		O&M	O&M			
Input/Fossil	change	120	421	2,158	1,491	4,190
	%	5.7%	12.2%	18.1%	82.5%	21.7%
Output/Fossil	change	115	419	2,128	1,378	4,040
	%	5.4%	12.1%	17.8%	76.2%	20.9%
Output/All	change	110	394	1,965	1,008	3,477
	%	4.9%	5.6%	14.0%	55.7%	13.9%

Table 4: Change in total production costs (million \$) (*continued*)

Total System Updating Option		Variable O&M	Fixed O&M	Fuel	Capital	Total
Input/Fossil	change	(12)	25	67	(50)	30
	%	-0.3%	0.2%	0.2%	-1.1%	0.1%
Output/Fossil	change	(16)	26	71	(54)	27
	%	-0.4%	0.2%	0.2%	-1.1%	0.0%
Output/All	change	(15)	17	79	(64)	17
	%	-0.3%	0.1%	0.2%	-1.4%	0.0%

Table 5: Average drop in marginal costs and retail prices in the ozone season (\$/MWh) relative to permanent allocation

20 Jurisdictions Updating Option		For producers <u>entirely</u> in 20 jurisdictions	For producers <u>partially</u> in 20 jurisdictions	For producers <u>outside</u> 20 jurisdictions	Total System
Input/ Fossil	change	2.0	1.3	0.4	1.1
	% of MC	9.4%	6.0%	1.8%	5.1%
	% of Retail Price	3.4%	2.1%	0.7%	1.9%
Output/ Fossil	change	1.9	1.3	0.3	1.0
	% of MC	9.1%	6.0%	1.7%	4.9%
	% of Retail Price	3.3%	2.1%	0.5%	1.7%
Output/ All	change	1.5	1.0	0.3	0.8
	% of MC	7.0%	4.8%	1.3%	3.7%
	% of Retail Price	2.6%	1.7%	0.4%	1.3%

Table 6: Magnitude of transfer from producers to consumers through updating systems relative to permanent allocation

Updating Option	20 Jurisdictions	Total System
Input/Fossil	\$1.25 billion	\$1.72 billion
Output/Fossil	1.19	1.59
Output/All	1.18	1.19

The transfer from producers to consumers was calculated by multiplying total nationwide electricity sales by the average nationwide drop in marginal costs of energy production caused by the updating system. The size of the transfer varies depending on the updating system used, but ranges from \$1.2 to \$1.8 billion. The cost of creating this transfer is equal to the increased generation costs noted above, in Table 4, and range from \$18 to \$29 million.

Table 7 shows that updating increases emissions within the 20 jurisdictions due to the shift in generation into the region. Its system-wide effects are more benign, because of the reduction in generation outside the region and the change in generation mix away from coal. The reductions in carbon and mercury shown in the lower panel of Table 7 take into account the increase in system-wide electricity generation that might be associated with the price reductions shown in Table 5.⁴

⁴See Appendix D for a discussion of the methodology for estimating the emission changes.

Table 7: Change in emissions relative to permanent allocation

20 Jurisdictions		NO_x	Carbon	Mercury
Updating Option		(MT)	(MMT)	(tons)
Input/Fossil	change	7.17*	15.42	0.09
	%	0.3%*	4.9%	0.3%
Output/Fossil	change	4.32*	14.38	0.08
	%	0.2%*	4.6%	0.2%
Output/All	change	4.09*	13.15	0.05
	%	0.2%*	4.0%	0.2%

Total System		NO_x	Carbon	Mercury
Updating Option		(MT)	(MMT)	(tons)
Input/Fossil	change	(22.23)	0.41	(0.18)
	%	-0.5%	0.0%	0.0%
Output/Fossil	change	(23.74)	(0.41)	(0.21)
	%	-0.5%	0.0%	0.0%
Output/All	change	(18.26)	(0.67)	(0.22)
	%	-0.4%	0.0%	0.0%

* NO_x emissions in the 20 jurisdictions are capped during the ozone season; these changes are during the non-ozone season.

C. Anticipated Effects for Additional Options

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As noted in Section III.D, EPA is also considering variants of the six core options analyzed in detail above. Though these variants were not modeled using IPM, analyses of their effects on individual units makes it possible to form a fairly clear picture of how their system-wide effects would differ from the core options. One of these variants is based on a permanent allocation system in which a progressively larger fraction of all allowances are distributed through an auction (instead of being distributed free to utilities). This option's effects would be the same as the permanent allocation options, except that the transfer of wealth represented by the free distribution of allowances to utilities would be replaced over time by a flow of revenues to the treasury. The effects of this flow would depend on how the government used the additional revenues.

EPA is also considering various ways to treat new units. Awarding allowances during their first years of operation (on the basis of current operating rates), as opposed to requiring new units to purchase allowances until they became established and built up a record of inputs and output, could provide a small additional incentive for building new units within the 20 jurisdictions. This increase in new units would, in turn, be expected to increase the economic and environmental effects associated with updating: total costs would be slightly higher, prices would be slightly lower, and NOx emissions outside the capped region would be slightly lower.⁵

A much more dramatic difference would be seen if EPA elects to limit allowance allocations to new units to the number they would actually need to use, based on their permitted emission rates. Because new units are subject to NSPS (new source performance standards), which tend to be more stringent than standards for existing units, they will generally be required to install SCR units, and will emit at rates well below the industry average even after the implementation of the 126 rules. If they are given allowances at the same rate as older units, they will tend to have many allowances available for sale – which will not be the case if they are given only as many as they need for their actual emissions. An IPM sensitivity run showed that a limit on the allowances received by new units would eliminate most of the shift in generation and costs characteristic of updating. The effect on prices would also be reduced, but to a small degree only, and effects on emissions would also change.

Finally, EPA considered an option very similar to the updating/output/fossil option examined above, in which the allowance allocations would be updated every four years instead of annually.

⁵The IPM modeling results presented in this report are based on runs in which new units were implicitly assumed to need to buy all of the allowances they needed for their first four years of operation. A sensitivity run was conducted to determine the effects of this simplification, with the finding that EPA's plan for awarding some allowances to new units even in their first few years would slightly increase the effects of updating.

Under this option, a unit's operation in a given year will affect the allocation it was to receive about seven years later, rather than four years later as in an annual updating option. This delay, which result from the need to average several years' operations together while leaving a lag of three years between the end of the base period and the beginning of the new allocation,

Table 8: Comparison of the effects of updating, with and without limits on allowances for new units relative to permanent allocation

	Effect on Price in 20 Jurisdictions	Effect on Generation in the 20 Jurisdictions	Effect on Total Cost	Effect on Uncapped NOx	Effect on Carbon
	\$/MWh, mills/kWh		Millions of dollars per year, system- wide	Thousands of Tons/year	Millions of Tonnes/year
Updating, Ouput/All units, No Limit for New Units (Relative to Permanent Allocation)	- \$1.5 /MWh	7.5%	\$17.8	-18.3	- 0.67
Updating, Ouput/All units, Limited Allocations for New Units (Relative to Permanent Allocation)	- \$1.3 /MWh	1.0%	\$4.6	-12.0	+1.14

reduces the present discounted value of the allocated allowances. For this reason, the effects of updating are somewhat reduced – by about 15 percent if the annual discount rate is 6 percent. Thus, the effects of this quadrennial updating option on prices, emissions, and generation patterns would be resemble a cross between the updating/output/fossil option and the updating/output/all option (because the latter also results in less valuable allocations to the fossil units).

Appendix A

Memo on Allowance Allocation Options, February 17, 1999

Appendix B

Numerical Example of the Effects of Permanent Allowance Allocation Mechanisms

This appendix presents a series of numerical examples to illustrate the point that how allowances are allocated under a “cap-and-trade” emission control program should not affect a utility’s decision of how much electricity to produce if the allowances are allocated “once-and-for-all” through a permanent allowance allocation system. The implementation of the emission control program itself may induce a utility to shut down a unit that was previously producing electricity, but the way in which the allowances are allocated should not affect the utility’s production decision. In other words, the utility’s choice of whether or not to shut down, and how much to produce if it does not shut down, is not affected by the type of allocation scheme chosen.

The following sections set up the assumptions upon which the examples are based, and then show how a profit-maximizing utility would act before and after a NO_x control program is instituted. The utility’s situation is compared for three possible ways of allocating allowances: if no allowances are allocated; if allowances are allocated on the basis of heat input; and if allowances are allocated on the basis of historical electricity output. In each case, the utility’s costs, revenues, and net revenues (profits) are found for various outputs (including for the case in which the utility shuts down). Under the standard assumption that the utility will choose the course that yields the highest profit, the analysis shows that the allowance allocation mechanism affects the utility’s profit but not its output.

1. Setting up the Problem: The Utility Prior to the Implementation of the Control Program

In this simple example, we assume that a utility owns only one generating unit, so its profits are equal to the total revenues from that unit’s output minus the total costs associated with the unit. The utility’s objective is to select an output level that maximize these profits, or to minimize its losses if losses are unavoidable.

Total revenues can be characterized as the price an electric utility receives for a MWh of electricity times the number of MWh of electricity sold by the utility in a year. Assume for simplicity that the price of electricity is set by the market at \$31.

Total costs consist of fixed and variable costs. Fixed costs are those that do not vary with output; in this example, we assume that these costs cannot be avoided even if the unit is permanently

closed. Assume that regardless of the amount of electricity produced, fixed costs are \$700,000 per year. Variable costs are costs (such as fuel and some kinds of maintenance) that do vary with the level of output (denoted as “Q”). In this case, we characterize variable costs such that they increase at an increasing rate with Q. The utility’s situation is presented in Table 1, which shows costs, revenues, and profits for several levels of output.

Table 1: Profits at Various Output Levels With No Emission Control Program							
Level of Output – MWh/year	0	100,000	281,250	400,000	500,000	656,250	750,000
Electricity Revenues – at \$31/MWh	0	3,100,000	8,718,750	12,400,000	15,500,000	20,343,750	23,250,000
Fixed Cost – dollars/year	700,000	700,000	700,000	700,000	700,000	700,000	700,000
Variable Operating Cost – \$25.75/MWh, rising by an additional \$0.40/MWh for every 100,000 MWh year	0	2,615,000	7,558,594	10,940,000	13,875,000	18,621,094	21,562,500
Profit (Revenue minus all costs)	0	-215,000	460,156	760,000	925,000	1,022,656	987,500
Maximum Profit Q for $Q > 0$						T	
Maximum Profit Q for any Q						T	

Table 1 demonstrates that the highest profit occurs at an output of 656,250 MWh/year. *This result can be obtained using calculus, as described on the following page, though following the mathematics is not vital for understanding the rest of the analysis.*

2. The Implementation of a Cap-and-Trade NO_x Control Program

Assume that the government decides to implement a cap-and-trade program in order to decrease the amount of NO_x emitted by electric utilities. The policy is designed to reduce the amount of NO_x emitted to 0.15 lbs per mmBTU or about 1.5 lbs per MWh of electricity. A utility cannot affect the government's initial allocation of allowances, and no adjustments are made to the allowance allocation after the initial distribution. Assume that allowances are given away to electric utilities on the basis of a historical measure such as fuel use or electricity output.

Using Calculus to Find Maximum Profit Quantities

Table 2 shows the cost, revenue, and profit functions for the utility prior to the implementation of the emission control program. To find the Q that gives the maximum profit using calculus, we find the “first order condition” (that is, we take the derivative of the total profit function with respect to Q and set it equal to zero) and solve for Q .

Table 2: The Profit-Maximizing Output Decision Prior to the Emission Control Program	
Revenues	$31 * Q$
Costs	$700,000 + 25.75 * Q + 0.000004 * Q^2$
Profits = Revenues - Costs	$(31 * Q) - (700,000 + (25.75 * Q + 0.000004 * Q^2))$
First-Order Condition	$31 - (25.75 + (2 * 0.000004 * Q)) = 0$
Profit-Maximizing Output	656,250 MWh
Profit at 656,250 MWh	\$1,022,656

Notice that the fixed costs drop out of the equation entirely when the derivative is taken – the equation specifying the maximum profit looks the same no matter what the fixed costs. This shows why, mathematically, the fixed costs are not relevant to the utility’s output decision.

Solving for the profit-maximizing quantity of electricity, we find $Q = 656,250$. In other words, the electric utility maximizes its profits when it produces approximately 656,250 MWh of electricity in a year. If the maximum generating capacity of the unit is 750,000 MWh of electricity in a year, then producing 656,250 MWh/year is approximately equivalent to the utility running at 88 percent of capacity all year-round.

By substituting the profit-maximizing quantity into the profit equation, we find that the electric utility is making a profit of \$1,022,656.

The costs imposed by the implementation of the allowance system are two-fold: First, the utility faces a fixed control-equipment cost of \$450,000/year. However, the fixed control cost is avoidable if the utility shuts down the unit and therefore does not install the control equipment. Second, the utility faces a variable control cost of \$3.00/MWh, which includes both the cost of running the control equipment and the costs of buying allowances to cover the unit’s residual emissions.

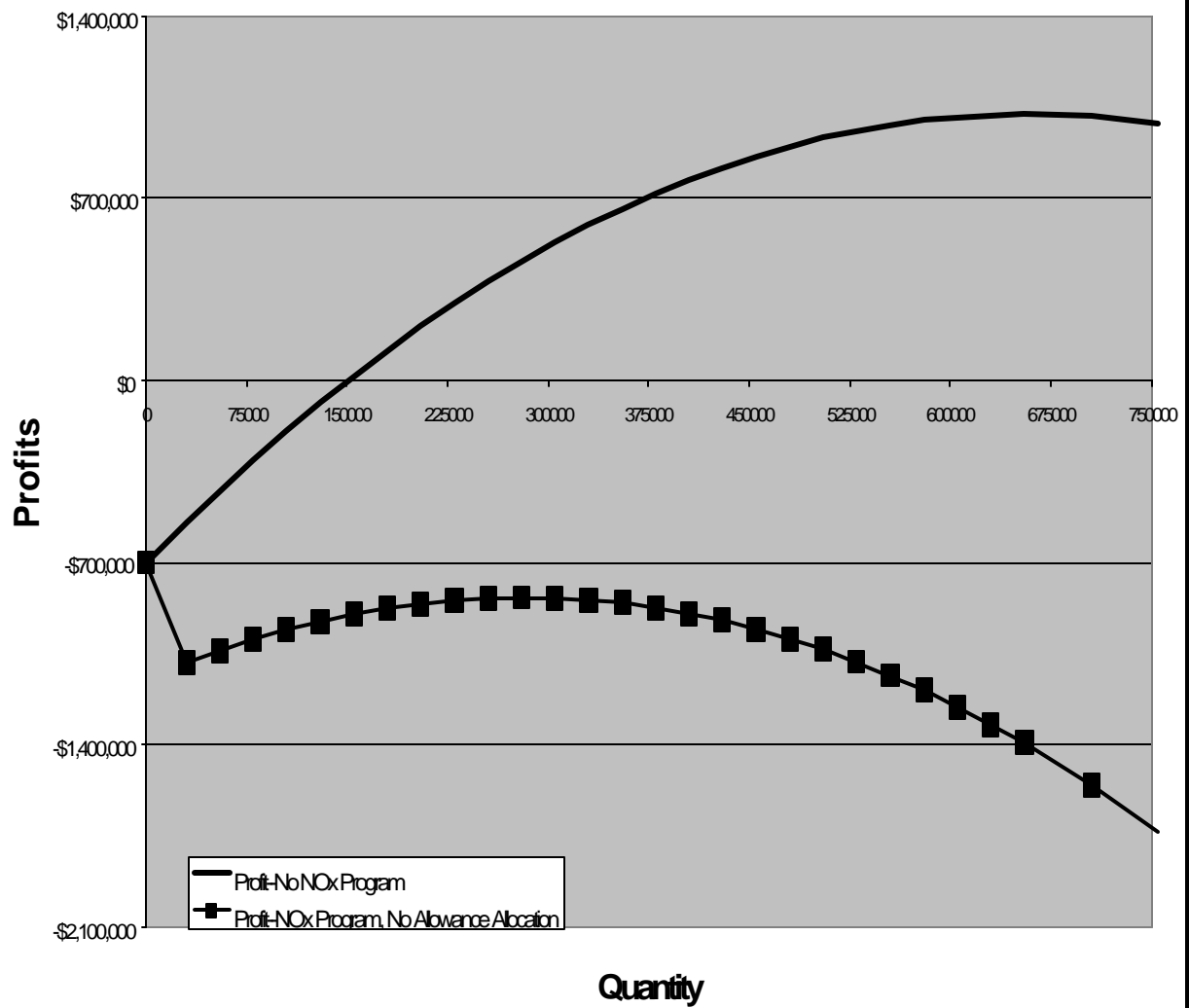
Suppose, as one possible case, that the utility is allocated no allowances at all; it must purchase

any allowances it needs. Its situation is shown in Table 3. The problem is also explained using calculus in table 4. If the utility decides to produce a positive amount of electricity at the unit, it will maximize its profits when $Q = 281,250$ MWh/year. If the utility produces 281,250 MWh, it will operate at a loss of \$833,594.

To determine if this is the best that the utility can do, we compare the maximum profit obtainable at the unit when it produces a positive amount of electricity to its profits when it does not produce any electricity at that unit. If the utility shuts the unit down, then it avoids the fixed control-equipment cost of \$450,000 and operates at a loss of \$700,000.

Table 3: Profits at Various Output Levels Under an Emission Control Program With No Allowances Allocated							
Level of Output – MWh/year	0	100,000	281,250	400,000	500,000	656,250	750,000
Electricity Revenues – at \$31/MWh	0	3,100,000	8,718,750	12,400,000	15,500,000	20,343,750	23,250,000
Fixed Cost – dollars/year	700,000	700,000	700,000	700,000	700,000	700,000	700,000
Variable Operating Cost – \$25.75/MWh, rising by an additional \$0.40/MWh for every 100,000 MWh year	0	2,615,000	7,558,594	10,940,000	13,875,000	18,621,094	21,562,500
Fixed Control Equipment Cost	0	450,000	450,000	450,000	450,000	450,000	450,000
Variable Control Cost (including allowance purchase cost)	0	300,000	843,750	1,200,000	1,500,000	1,968,750	2,250,000
Profit (Revenue minus all costs)	-700,000	-965,000	-833,594	-890,000	-1,025,000	-1,396,094	-1,712,500
Maximum Profit Q for $Q > 0$			T				
Maximum Profit Q for any Q	T						

Figure 1: Profits Before and After the Permit System



Using Calculus to Find the Maximum Profit Quantity, Part 2

Table 4 shows the cost, revenue, and profit functions for the utility under the emissions control program in the case where no allowances have been allocated to the utility. To find the Q that gives the maximum profit using calculus, we find the “first order condition” (that is, we take the derivative of the total profit function with respect to Q and set it equal to zero) and solve for Q .

Table 4: The Profit-Maximizing Output Decision Under an Emission Control Program With No Allowances Allocated	
Revenues	$31 * Q$
Operating Costs	$700,000 + 25.75 * Q + 0.000004 * Q^2$
Emissions Control Cost When $Q > 0$	$3 * Q + 450,000$
Profits When $Q > 0$ = Revenues - Operating Costs - Emissions Control Costs	$31 * Q - (700,000 + 25.75Q + 0.000004 * Q^2 + 3 * Q + 450,000)$
First-Order Condition	$31 - (25.75 + (2 * 0.000004 * Q) + 3) = 0$
Profit-Maximizing Output When $Q > 0$	281,250 MWh
Profit at 281,250 MWh	\$ - 833,594
Profit When $Q = 0$	- \$ 700,000

If the utility decides to produce a positive quantity of electricity, it maximizes profits when $Q = 281,250$ MWh/year. By substituting the profit-maximizing quantity into the profit equation, we find that the electric utility operates at a profit of - \$833,594. However, if the utility were to instead shut down and produce no electricity ($Q = 0$), it would have a smaller loss because it would avoid the cost of emissions control entirely. The utility’s profit at $Q = 0$ is equal to - \$700,000.

Thus, if the utility does not receive any allowances from the government in the initial allocation process, the profit-maximizing output is 0 MWh of electricity. Figure 1 illustrates the effect of the implementation of an allowance system on the utility. Not surprisingly, when a utility faces an additional cost, it produces less electricity. In this case, the cost of the allowance system causes the utility to shut down and stop producing electricity.

3. Does the Initial Allocation of Allowances Make a Difference to the Utility’s Output Decision?

Does the situation improve when the electric utility is given a certain number of allowances? We examine two cases of permanent allocations: one in which the utility is allocated a certain number of allowances based on its past fuel use and one in which it is allocated allowances on the basis of its past electricity output. Unless electricity production always requires exactly the same fuel input per unit of output, the number of allowances a utility is allocated will differ with the measure used to distribute allowances.

a. (Permanent) Input-Based Scenario

For the purpose of this example, we assume that the electric utility is more efficient than average, with a heat rate of 7,500. In other words, it uses 7.5 million BTU to produce 1 MWh of electricity (we assume that the average firm uses 10 million BTU to produce 1 MWh of electricity). Suppose that, based on its historical performance, the utility is allocated 369 allowances per year.

Assume that the market value of each allowance is \$3,000. The firm has no control over the number of allowances it receives and the number of allowances allocated to the utility does not change over time. Therefore the value to the utility of the initial allocation is fixed (it does not depend on Q). When the initial allocation of allowances is based on past fuel use, the electric utility receives allowances worth \$1,107,000. The utility can sell all of the allowances, and then purchase any that it needs to cover its NO_x emissions, or it can hold back from the market all of the allowances it needs – either way, it will be better off by \$1,107,000/year.

If the utility produces a positive amount of electricity at the unit, it will maximize its profits when $Q=281,250$ MWh of electricity per year. If the utility produces 281,250 MWh/year it will make a profit of \$273,406. However, if the utility shuts the unit down, it will make an even greater profit. It will avoid the cost of installing the control equipment and earn a profit of \$407,000. Thus, a profit-maximizing utility will still produce 0 MWh of electricity, despite the fact that it now receives a substantial one-time subsidy of \$1,107,000 in the form of allowances.

<p>Table 5: Profits at Various Output Levels Under a Control Program With 369 Allowances Allocated</p>

Level of Output – MWh/year	0	100,000	281,250	400,000	500,000	656,250	750,000
Electricity Revenues – at \$31/MWh	0	3,100,000	8,718,750	12,400,000	15,500,000	20,343,750	23,250,000
Value of Allocated Allowances	1,107,000	1,107,000	1,107,000	1,107,000	1,107,000	1,107,000	1,107,000
Fixed Cost – dollars/year	700,000	700,000	700,000	700,000	700,000	700,000	700,000
Variable Operating Cost – \$25.75/MWh, rising by an additional \$0.40/MWh for every 100,000 MWh year	0	2,615,000	7,558,594	10,940,000	13,875,000	18,621,094	21,562,500
Fixed Control Equipment Cost	0	450,000	450,000	450,000	450,000	450,000	450,000
Variable Control Cost (including allowance purchase cost)	0	300,000	843,750	1,200,000	1,500,000	1,875,000	2,250,000
Profit (Revenue minus all costs)	407,000	142,000	273,406	217,000	82,000	-289,094	-605,500
Maximum Profit Q for $Q > 0$			T				
Maximum Profit Q for any Q	T						

Using Calculus to Find the Maximum Profit Quantity, Part 3

When the utility is given 369 allowances, the profit function is amended to include a \$1,107,000 subsidy (369 allowances each valued at \$3000). Profits when $Q > 0$ are characterized by the following expression.

$$31 * Q - (700,000 + 25.75Q + 0.000004 * Q^2 + 3 * Q + 450,000) + 1,107,000 .$$

To find the Q that gives the maximum profit using calculus, we find the “first order condition” (that is, we take the derivative of the total profit function with respect to Q and set it equal to zero) and solve for Q . Despite the increase in the number of allowances allocated to the utility, the first-order condition is identical to the first-order condition when the utility does not receive any allowances. Since the number of allowances a utility receives cannot be affected by the utility’s choice of Q , the utility treats any revenues from these allowances as fixed. Thus, the subsidy falls out of the equation when the derivative is taken.

Table 6: The Profit-Maximizing Output Decision Under an Emission Control Program With 369 Allowances Allocated

First-Order Condition	$31 - (25.75 + (2 * 0.000004 * Q) + 3) = 0$
Profit-Maximizing Output When $Q > 0$	281,250 MWh
Profit at 281,250 MWh	\$ 273,406
Profit When $Q = 0$	\$ 407,000

Because the first-order condition has not changed, the utility’s profit-maximizing Q also remains unchanged. Regardless of the number of allowances allocated to the utility, it maximizes profits by shutting down the unit and producing no electricity ($Q = 0$). The utility’s profit at $Q = 0$ is equal to \$407,000.

b. (Permanent) Output-Based Scenario

If a utility with an unusually efficient unit receives allowances on the basis of its historical output of electricity rather than its fuel input, it is likely to receive relatively more allowances. Table 7 illustrates the utility’s situation if, under an output-based allocation mechanism, it receives 492 allowances.

Table 7: Profits at Various Output Levels Under a Control Program With 492 Allowances Allocated							
Level of Output – MWh/year	0	100,000	281,250	400,000	500,000	656,250	750,000
Electricity Revenues – at \$31/MWh	0	3,100,000	8,718,750	12,400,000	15,500,000	20,343,750	23,250,000
Value of Allocated Allowances	1,476,000	1,476,000	1,476,000	1,476,000	1,476,000	1,476,000	1,476,000
Fixed Cost – dollars/year	700,000	700,000	700,000	700,000	700,000	700,000	700,000
Variable Operating Cost – \$25.75/MWh, rising by an additional \$0.40/MWh for every 100,000 MWh year	0	2,615,000	7,558,594	10,940,000	13,875,000	18,621,094	21,562,500
Fixed Control Equipment Cost	0	450,000	450,000	450,000	450,000	450,000	450,000
Variable Control Cost (including allowance purchase cost)	0	300,000	843,750	1,200,000	1,500,000	1,968,750	2,250,000
Profit (Revenue minus all costs)	776,000	511,000	642,406	586,000	451,000	79,906	-236,500
Maximum Profit Q for $Q > 0$			T				
Maximum Profit Q for any Q	T						

When the utility produces a positive amount of electricity at the unit, the profit-maximizing quantity is to produce 281,250 MWh of electricity (just as in the other two allowance allocation cases). If the utility produces 281,250 MWh/year it will make a profit of \$642,406. However, if the utility shuts the unit down, it will make an even greater profit. It will avoid the cost of installing the control equipment and earn a profit of \$776,000. Thus, a profit-maximizing utility will still produce 0 MWh of electricity, despite the fact that it now receives a substantial one-time subsidy of \$1,476,000 in the form

Using Calculus to Find the Maximum Profit Quantity, Part 4

An Emission Control Program - Allowances Allocated on the Basis of Electricity Production

When the utility is given 492 allowances, the profit function is amended to include a \$1,476,000 subsidy (492 allowances each valued at \$3000). Profits when $Q > 0$ are characterized by the following expression.

$$31 * Q - (700,000 + 25.75Q + 0.000004 * Q^2 + 3 * Q + 450,000) + 1,476,000$$

To find the Q that yields maximum profit, we solve for the “first order condition” (that is, we take the derivative of the total profit function with respect to Q and set it equal to zero) and solve for Q .

$$31 - (25.75 + (2 * 0.000004 * Q) + 3) = 0$$

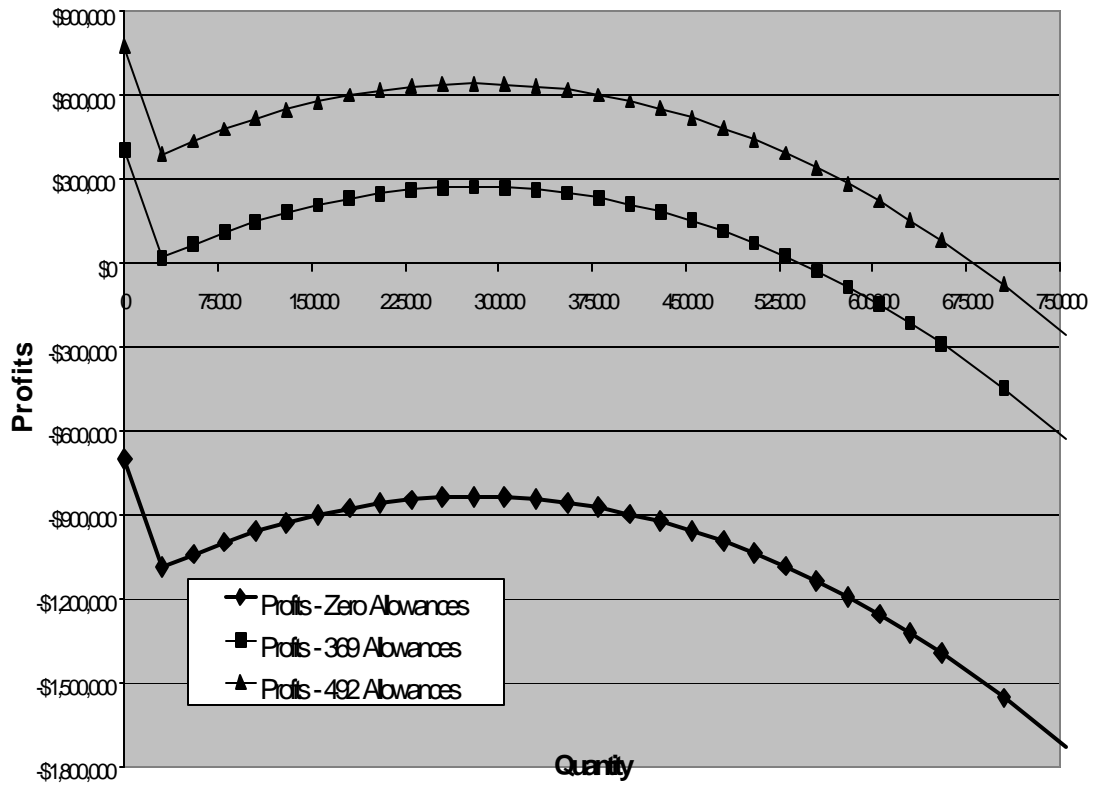
Again, the first-order condition is identical to the first-order condition when the utility receives fewer allowances from the government. In other words, the utility’s output decision is completely unaffected by its initial allocation of allowances. If a utility is making a profit, it will continue to operate at a profit regardless of the way in which the allowances are distributed. If it is instead operating at a loss and has to shut down, it will do so regardless of the number of allowances it is allocated.

Because the first-order condition has not changed, the utility’s profit-maximizing Q also remains unchanged. Regardless of the number of allowances allocated to the utility, it maximizes profits by shutting down the unit and producing no electricity ($Q = 0$). The utility’s profit at $Q = 0$ is equal to \$776,000.

of allowances.

Figure 2 illustrates the amount of profit made at each level of output when the utility receives no allowances, 369 allowances, and 492 allowances. Notice that, while the profit function has a local maximum of 281,250, it has a global maximum at 0 MWh of electricity under each scenario. In other words, the quantity at which the utility maximizes profit is the same even when the number of allowances allocated to the utility changes. While the shape of the profit function does not change with the number of allowances received, it does shift up as the number of allowances the utility receives increases. Thus, while the output decision of the utility is unaffected, the amount of profit the utility makes changes with the number of allowances allocated. The reason for this is simple: a utility that is allocated a larger number of allowances receives a larger one-time subsidy from the government.

Figure 2: The Effect of Allowance Allocation on Output and Profit



Appendix C

Effects of Permanent Allocations in a Series of Permanent Allocations

Economic theory strongly supports the prediction that the allocations made on a permanent, once-and-for-all basis will have no effect on output decisions made after the allocations have been set. A more subtle question is whether the effects of a permanent allocation that is one of series of similar allocations would be more likely to change the actions of affected firms. This appendix considers each of these cases in turn.

Effects of Permanent Allocations Considered Individually

As discussed in Section IV of this report and in Appendix B, the basic reason for expecting that future power plant operations will be unaffected by the size of permanent allocation is that the benefits of those allocations fall into the category of “sunk” costs or benefits. Under a permanent once-and-for-all allowance allocation system, the number of allowances each firm receives is based either on either past electricity production or past fuel use and cannot be affected by the future decisions of the firm. The economic benefits associated with the initial allocation of allowances are therefore no longer relevant to the firm’s subsequent output decisions regardless of the initial distribution of allowances. Section IV cites recent work on tradable permit allocations by Jensen and Rasmussen⁶, and an introductory economics text by Dornbusch and Fischer,⁷ in support of this point. A detailed numerical example is presented as Appendix B to illustrate the fact that permanent allocations do not affect the output at which profits are maximized, and therefore should have no effect on output decisions.

It could be argued, though, that there could be an indirect incentive for increasing or maintaining output if the program based on a permanent allocation were expected to be one in a series of emission control programs. For example, suppose the section 126 rule awarded allowances on a permanent basis, using historical electricity output from five years before the start of the program. Suppose also that the affected industry expected these rules to be followed by rules covering SO₂, mercury, and then CO₂ at five year intervals. The system for allocating allowances under the section 126 rule could be interpreted as an indication of how EPA would design the control programs for the other pollutants. If so, producers could be shown to have some incentive to increase (or at least maintain) their output in the years that might turn out to be the base period for the next permanent allowance allocation. By this

⁶Jesper Jensen and Tobias N. Rasmussen, “Allocation of CO₂ Emission Permits: a General Equilibrium Analysis of Policy Instruments,” unpublished manuscript, December 21, 1998

⁷Dornbusch and Fischer (1983). *Economics*. McGraw-Hill: New York, p. 180.

logic, the act of including a given class of units in the permanent allocation system for the section 126 rule would induce changes in their operators' expectations about the characteristics of future rules, and give them the incentive to maintain or increase output. This incentive might be strengthened if EPA announced that it intended to continue to establish allowance programs based on successive historical periods, in order to encourage increased output.

Though this effect is theoretically possible, its magnitude is likely to be very small for a number of reasons. First, it would not be credible for EPA to establish a program to give allowances historically in each successive regulatory program with the justification that this pattern would continue. The problem is that there are a limited number of major programs on the horizon, and once the last planned program has been implemented there is no reason for EPA to give out the allowances on a historical basis (because there would be no credible incentive to continue in operation through the next historical baseline period.) EPA could not be counted on to give out historically based allowances for the last program, and therefore would have no incentive to give out historically based allowances for the second-to-last, and so forth.

Second, the influence of EPA's NO_x allowance allocation on the perceived likelihood that EPA would give out allowances to particular classes of units in the next regulation could be quite small. EPA cannot make promises about how it will design future programs, and cannot dictate how States will allocate allowances. In addition, if all previous regulations are taken into account in projecting future allocation mechanisms, then the Title IV SO₂ allowance program, and other programs, will also have a strong influence. In this case, the influence of the section 126 rules will be diluted.

Third, the expected value of allowance streams from future regulations depends on the certainty that the future programs will go into effect at all. Industry cannot be sure that there will be a mercury, fine particulate, or CO₂ program, and therefore would tend to discount the expected value of getting allowances from them. Industry will also be unsure of the value of allowance streams from future regulations even given that they will be promulgated. Because of uncertain levels of stringency, uncertain geographic and sectoral coverage, uncertain cost-effectiveness of control technologies, and uncertain fuel and electricity prices, utility plant operators are likely to view future streams as highly uncertain. They can therefore be expected to apply a substantial risk discount to the expected value of these streams. In addition, because most of the value of the streams of allowances from future regulations will fall many years in the future, little of the stream of allowance values will be counted today.

Combining these observations suggests that permanent allowances under section 126 would have almost no influence on the future output levels of the units receiving the allowances.

Appendix D

Methodology for Estimating Carbon and Mercury Emission Changes Resulting from Updating

The first step in estimating the changes in carbon and mercury emissions attributable to an updating allowance allocation is to find the annual system-wide changes in these pollutants under the assumption that system-wide output does not change. These estimates are calculated directly by IPM, which assumes no change in system-wide demand in response to updating. It can be expected, however, that the price reductions caused by updating will result in more total electricity being sold. This incremental demand will be met by fossil generation, which will result in higher emissions of mercury and carbon. Because preliminary analyses suggested that these added emissions could be significant, we developed a simple method for assessing them quantitatively.

We first found the nationwide annual change in prices in absolute (mills/kWh) terms, based on IPM results, for an updating option compared to the permanent options. We then divided this change by 58 mills per kWh, a typical retail price for electricity, to determine the percentage change in retail electricity prices. Using a price elasticity of demand for electricity of -0.3, we estimated the change in quantity demanded associated with this percentage change in price. Using the fact that about 77 percent of total generation is from fossil fuels, we found the percentage increase in fossil generation that would result from this percentage change in total generation under the assumption that all of the increased demand would be met by fossil generation.

Given the estimated percentage change in fossil generation, we calculated the percentage change in carbon emissions from utilities by examining modeling results for a scenario in which fossil generation increased in response to growing demand. For this calculation of relative changes in carbon and mercury to fossil generation, we used projections of fossil generation and emissions of carbon and mercury for the 20 jurisdictions (because the price changes caused by updating, and therefore the increased demand, would be concentrated within the 20 jurisdictions).

Following these steps, we were able to trace the price changes to percentage changes in fossil generation, and then to percentage changes in carbon and mercury emissions. Finally, the percentage changes in carbon and mercury emissions were multiplied by baseline carbon and mercury emissions to find absolute changes in emissions. These calculations are laid out in the following table for the three updating options.

Exhibit D-1

Calculation of changes in uncapped pollutants, including effects of increased generation

	Ouput/all units	Output/ fossil only	Input/ fossil only	Basis of Calculation
Changes due to dispatch changes				
MMT change in carbon emissions	-1.58	-1.60	-0.84	IPM Modeling Results, Assuming No Change in Electricity Use
Metric ton change in Hg emissions	-0.29	-0.30	-0.28	IPM Modeling Results, Assuming No Change in Electricity Use
Changes due to price reductions				
Absolute electricity price reduction in mills/kWh, systemwide, O3 season	-0.77	-1.01	-1.05	IPM results, years 2000 -- 2015
% changes in retail electricty prices, O3 season	-1.31%	-1.73%	-1.80%	Dividing by 58 mills/kWh, based on average revenues of utilities in EIA's Form 861 for 1990
% changes in retail electricity prices, annual average	-0.55%	-0.72%	-0.75%	Multiply by 5/12 to approximate annual price effects
% change in electricity generation	0.16%	0.22%	0.23%	Multiply by -0.3 as an approximate price elasticity, based on ICF research, implicit EIA
% change in fossil generation	0.21%	0.28%	0.29%	Divide by 0.77, the fraction of generation in the 126 region from fossil, over 2004 through 2019, from IPM projections, non-updating
% change in carbon emissions	0.15%	0.19%	0.20%	Multiply by 0.68, which is the ratio of percentage changes in carbon in the 126 region to percentage changes in fossil generation, from 2000 to 2016
% change in Hg emissions	0.11%	0.14%	0.15%	Multiply by 0.50, which is the ratio of percentage changes in Hg in the 126 region to percentage changes in fossil generation, from 2000 to 2016
MMT increase in carbon emissions	0.91	1.20	1.24	Multiply by systemwide annual millions of metric tons of carbon emitted from fossil generation, from IPM projections
Metric ton increase in Hg emissions	0.07	0.09	0.10	Multiply by system-wide annual metric tons of Hg emitted from fossil generation, from IPM projections
Net changes				
MMT change in carbon emissions	-0.67	-0.41	0.41	Sum of dispatch and generation-related changes
Metric ton change in Hg emissions	-0.22	-0.21	-0.18	Sum of dispatch and generation-related changes